OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

DRAFT

MEMORANDUM **May 17, 2022**

TO: Phillip Fielder, P.E., Chief Engineer, Air Quality Division

THROUGH: Rick Groshong, Compliance and Enforcement Manager

THROUGH: Phil Martin, P.E., Engineering Manager, Existing Source Permits Section

THROUGH: Tom Richardson, P.E., Rules & Planning Section

FROM: Ryan Buntyn, P.E., New Source Permits Section

SUBJECT: Evaluation of Permit Application No. **2019-0630-TVR2**
Valero Refining Company - Oklahoma
Valero Ardmore Refinery (SIC 2911)
DEQ Facility ID: 1534
Ardmore, Carter County
Latitude: 34.206° N Longitude: -97.104° W
Directions from I-35: east three miles on Highway 142

SECTION I. INTRODUCTION

Valero Refining Company – Oklahoma (Valero) operates a petroleum refinery (SIC 2911, NAICS 324110) in Ardmore. The facility is currently operating under Permit No. 2012-1523-TVR (M-1), which was issued on October 16, 2014. Subsequent to the issuance of that permit, Valero has proposed nine separate minor modifications to their Title V permit and Valero has obtained four construction permits. In addition, Valero requested an applicability determination to address a physical change that was made without requiring a permit modification. In addition, Valero has requested renewal of their Title V operating permit and this renewal incorporates all the permit modifications requested subsequent to the issuance of the most recent operating permit. A brief description of each application is provided below. A more detailed description and a project analysis for each project are provided in Section III.

Construction Permit No. 2012-1523-C (M-2)

The application was submitted on August 2, 2014. The application requested authorization to construct a new 600 psig (pounds per square inch gauge pressure) steam production boiler with a maximum heat input of 285.3 MMBtu/hr (million British thermal units per hour). Valero requested a limit to keep project emission increases below the Prevention of Significant Deterioration (PSD) threshold and the permit underwent Tier II review. The permit was issued on April 22, 2015.

Application for Minor Modification No. 2012-1523-TVR (M-3)

The application was submitted on December 22, 2014. Valero requested a minor modification to allow changes to be made in the recovered oil processing at the refinery. The project was cancelled and the application was withdrawn.

Construction Permit No. 2012-1523-C (M-4)

The application was submitted on February 29, 2016. The application requested a construction permit to incorporate requirements from a consent decree (Civil Action No. SA-05-CA-0569) into the permit. No new emissions units or modifications were authorized by this permitting action. This construction permit provided the basis on which these conditions agreed to in the consent decree may be incorporated into the Title V operating permit. This application underwent Tier I review. The permit was issued on April 12, 2016.

Permit No. 2012-1523-C (M-5)

This permit was issued as an administrative amendment to Permit No. 2012-1523-C (M-4). Valero requested a slight change in specific condition language to conform with the requirements of the consent decree. The administrative amendment was issued on June 13, 2016.

Application for Minor Modification No. 2012-1523-TVR (M-6)

The application was submitted on May 31, 2016. Valero requested a minor modification to incorporate an Alternative Monitoring Plan for the Fluidized Catalytic Cracking Unit (FCCU) Flue Gas Scrubber, to incorporate VOC and PM emissions estimates for two existing cooling water towers, to change the classification of a diesel-driven water pump (from an insignificant activity to EUG 40), and to address a number of minor administrative issues (corrections and updates to permit language).

Construction Permit No. 2012-1523-C (M-7)

This permit was issued as an administrative amendment to Permit No. 2012-1523-C (M-5). Valero requested a slight change in specific condition language to conform with the requirements of the consent decree. The administrative amendment was issued on June 30, 2016.

Application for Minor Modification No. 2012-1523-TVR (M-8)

The application was submitted on January 9, 2017. Valero requested a minor modification to incorporate the requirements for operation of the 600 psig, 285.3 MMBtu/hr steam production boiler into the Title V operating permit. Construction of this emission unit was authorized by Permit No. 2012-1523-C (M-2). This application also requested a number of administrative changes, including the consolidation of multiple leak detection a repair (LDAR) emission units into a single emissions unit under Emission Unit Group (EUG) 31. Most of these changes were authorized by the construction permit and their incorporation into the operating permit was requested by this permitting action. Because the construction permit underwent Tier II public review, and because the additional changes requested are considered to be minor modifications under Oklahoma Administrative Code (OAC) 252:100-8-7.2(b)(1), this permitting action is classified as Tier I.

Application for Minor Modification No. 2012-1523-TVR (M-9)

The application was submitted on August 18, 2017. Valero requested a minor modification to allow an additional cell to an existing cooling tower and to redistribute the loads to two existing cooling towers.

Application for Applicability Determination No. 2012-1523-AD (M-10)

The application was submitted on January 30, 2018. Valero requested an applicability determination to confirm that they could rebuild Tank T-1018 under the current permit with or without performing a minor modification to the Title V operating permit. The finding of the determination was that the physical change did not require a modification to the Title V operating permit. This determination was issued on August 11, 2020.

Application for Minor Modification No. 2012-1523-TVR (M-11)

The application was submitted on January 30, 2018. Valero requested a minor modification to authorize the replacement of an existing process heater (H-407) with a new steam reboiler which uses steam from an existing 600 pound steam boiler (B-15001).

Application for Minor Modification No. 2012-1523-TVR (M-12)

The application was submitted on January 30, 2018. Valero requested a minor modification to authorize the installation of a new emergency generator engine for a new administration building.

Application for Minor Modification No. 2012-1523-TVR (M-13)

The application was submitted on July 3, 2018. Valero requested a minor modification to authorize installation of replacement feed filters and a new filter tray in the catalytic feed hydrotreater (CFHT) reactor R-6502 (R-2).

Application for Minor Modification No. 2012-1523-TVR (M-14)

The application was submitted on September 5, 2019. Valero requested a minor modification to authorize an increase in the flow rate of supplementary fuel gas (also referred to as “sweep gas”) to the Alky Flare, which is designated as Emission Unit (EU) HI-81002, in Emissions Unit Group (EUG) 14.

Application for Renewal of the Title V Operating Permit No. 2019-0630-TVR2

The application was submitted on May 21, 2019. Valero requested renewal of the Title V operating permit.

On issuance of this permit, Permit No. 2012-1523-TVR (M-1) will be superseded and cancelled.

The remainder of this memorandum is organized as follows.

SECTION II. FACILITY PROCESS DESCRIPTIONS

The Valero Ardmore Refinery's primary standard industrial classification (SIC) code is 2911. The refinery processes medium and sour crude oils from both the domestic and foreign markets. Major production and processing units include the following units at their nominal capacities: a 100 thousand barrel per day (MBPD) crude unit, a 34 MBPD vacuum-tower unit, a 14 MBPD asphalt blow-still unit, a 11.4 MBPD polymer modified asphalt (PMA) unit, a 32 MBPD distillate hydrogenation desulfurization (DHDS) unit, a 32 MBPD catalytic feed hydrotreater (CFHT) unit, a 15 MBPD Hydrocracking Unit (HCU), a 30 MBPD fluid catalytic cracking unit (FCCU) with two-stage regeneration, a 33 MBPD naphtha hydrotreater (NHT) unit, a 26 MBPD catalytic reformer unit, a 20.0 MBPD Sat-Gas Unit, a 7.5 MBPD alkylation unit, a 25.0 MBPD Bensat unit, a 119 long ton per day (LTPD) sulfur recovery unit (SRU), a 130 LTPD SRU, and a 29 million standard cubic feet per day (MMSCFD) hydrogen production unit. The majority of raw crude oil is received on-site through utilization of an integrated pipeline system.

The refinery's process heaters, steam boilers, compressors, and generators are capable of producing approximately 2.4 billion BTU/hr of energy transfer. The refinery has approximately 2.8 million barrels of refined product storage capability. Products include conventional and reformulated low sulfur gasoline, diesel fuel, asphalt products, propylene, butane, propane, and sulfur. Refined products are transported via pipeline, railcar, and tank truck.

Basically, the refining process does four types of operations to crude oil:

1. Separation: Liquid hydrocarbons are distilled by heat separation into gases, gasoline, diesel fuel, fuel oils, and heavier residual material.
2. Conversion:
    i. *Cracking*: This process breaks or cracks large hydrocarbons molecules into smaller ones. This is done by thermal or catalytic cracking.
    ii. *Reforming*: High temperatures and catalysts are used to rearrange the chemical structure of a particular oil stream to improve its quality.

iii. *Combining*: Chemically combines two or more hydrocarbons such as liquid petroleum gas (LPG) materials to produce high grade gasoline.

3. Purification: Converts contaminants to an easily removable or an acceptable form.
4. Blending: Mixes combinations of hydrocarbon liquids to produce a final product(s).

Crude Oil Processing Unit

The purpose of the crude oil processing unit is to separate the crude oil into the primary fractions of crude oil: liquefied petroleum gas (LPG), light straight run naphtha, heavy straight run naphtha, straight run kerosene, light straight run diesel, heavy straight run diesel, atmospheric gas oil, and reduced crude oil. Additionally, by nature of the process, a small amount of off-gas and slop wax is also produced. All of these primary fractions are considered intermediate products which require additional processing in other unit operations or processing units before the products may be classified as refinery grade products.

The crude oil processing unit receives a blended crude charge from a proportioned and planned recipe of sweet and sour crude oil feedstock(s). The blended crude oil feedstock is processed through a series of product/feed pre-heat exchangers and then the crude-oil desalting unit operation. After the desalter unit operation, the crude oil is further processed through another series of feed/product pre-heat heat exchangers and then proportioned through three crude-oil pre-heat process heaters (H-101, H-102A and H-102B). Upon exiting the crude-oil preheat process heaters, the crude oil recombines into a single mixture and then enters the crude-oil atmospheric distillation tower (T-102). The crude oil atmospheric tower separates the crude oil into seven product streams: reduced crude, atmospheric gas oil, heavy diesel, light diesel, kerosene, heavy naphtha, and an overhead vapor. The overhead vapor from T-102 is processed through a series of condensers and then into an overhead accumulator. The vapor stream from the overhead accumulator is vapor-ballasted with the light naphtha contactor (T-113). The accumulator's liquid stream is processed to the light-naphtha contactor. The bottoms product of the light naphtha contactor is processed to the saturated gas plant processing unit's feed surge drum (V-305).

The heavy naphtha stream from T-102 is processed through a series of cooling heat exchangers and to storage. The kerosene stream from T-102 is processed to the kerosene steam stripper which is vapor-ballasted with T-102. The liquid product from the kerosene steam stripper is processed to the DHDS feed surge drum (V-608). The light diesel from T-102 is processed to the light diesel steam stripper (T-111). The product stream from the light diesel steam stripper is processed to the DHDS feed surge drum (V-608). The heavy diesel stream from T-102 is processed to the heavy diesel steam stripper (T-114). The product stream from the heavy diesel steam stripper is processed to HCU feed surge drum (V-6701). The atmospheric gas oil (AGO) stream from T-102 is processed to the AGO steam stripper (T-112). The product from the AGO steam stripper T-112 is processed to CFHT feed surge drum (V-6501).

Vacuum Processing Unit

The purpose of the reduced crude vacuum processing unit is to separate light vacuum gas oil (LVGO) and heavy vacuum gas oil (HVGO) from asphalt. The process also produces a small quantity of off-gas. The reduced crude from the crude oil processing unit's fractionation tower (T-102) is processed to the vacuum tower (T-106) pre-heat process heater (H-103). However, a slip stream of reduced crude is processed to the CFHT feed surge drum (V-6501). Once the reduced crude exits the vacuum tower process heater (H-103), the heated reduced crude is processed to the vacuum tower (T-106) where a single-stage flash vaporization is achieved. The single-stage flash vaporization (operating under a vacuum) yields hot-well vapors, LVGO, HVGO, slop wax, and vacuum tower bottoms (asphalt). The hot-well vapors from T-106 are processed to the fuel gas amine treating process unit. The light vacuum and heavy vacuum gas oils and slop wax are processed to the CFHT feed surge drum (V-6501). The vacuum tower asphalt may either be processed to the asphalt blowing still or to storage, or a combination of the two. Additionally, a slip stream of vacuum tower asphalt may as well be processed to the CFHT feed surge drum (V-6501).

Asphalt Blowing Still Processing Unit

The purpose of the asphalt blowing process is to dehydrogenate short-chained residuals contained in the vacuum tower bottoms asphalt, resulting in both oxidation and polycondensation products. The aim of the blowing process is to enhance the formation of asphaltenes. The blowing still increases the overall molecular size of the asphaltenes that are already present in the vacuum tower bottoms asphalt feedstock and also forms additional asphaltenes. Oxidized asphalts are used almost entirely for industrial applications such as roofing, flooring mastics, pipe coatings and paints. The raw materials (grades of asphalt) for these products are specified and designated by both softening point and penetration tests. In example, an eighty-five/forty (85/40) grade asphalt is an oxidized grade of asphalt with a softening point of 85ºC and a penetration of 40.

The penetration and softening point of the blown asphalt are affected by viscosity of the feedstock, temperature in the blowing still, residence time in the blowing still, origin of the crude oil used to manufacture the feedstock, and the air-to-feed ratio. The vacuum tower (T-106) bottom's asphalt is processed through a series of preheat heat exchangers and is then introduced into the asphalt blowing still (T-107) just below the normal liquid level. Air is blown through the asphalt by means of compressed air flowing through an air distributor located at the bottom of the blowing still. The air is not only a reactant in the oxidation and polycondensation reactions but also serves to agitate and mix the liquid asphalt in the blowing still, thereby effecting an increase of the surface area and the rate of reaction. Oxygen is consumed by the reaction as the air ascends through the material. Steam and water are sprayed into the vapor space above the liquid level, the former to suppress foaming and dilute the oxygen content of waste gases and the latter cools the vapor to prevent after-burning. The blown asphalt product is processed to storage as a finished product. That asphalt which is bypassed around the asphalt blowing still is also considered a finished product. Vapors from the asphalt blowstill are processed through a caustic scrubber in route to the blowing still incinerator.

Distillate Hydrogenation Desulfurization (DHDS) Processing Unit

The purpose of the DHDS processing unit is to remove sulfur compounds from distillate and producing low and ultra-low sulfur distillate. The sulfur removal process requires the use of a hydrogenation desulfurization catalyst. Hydrogen gas is also consumed in the distillate hydrogenation desulfurization reactions while hydrogen sulfide (H_2S) gas is produced. The H_2S gas is absorbed by an amine absorber to form a weak amine salt. The amine solution is processed to the amine regeneration processing unit's feed surge drum. The DHDS Unit consists of a feed section, reactor section, effluent separator section, recycle gas amine treating section, and a fractionation section.

Light diesel from the crude unit atmospheric fractionation tower's (T-102) light diesel side stripper (T-111), kerosene from the crude unit atmospheric fractionation tower's (T-102) kerosene side stripper (T-109), AGO from the crude unit atmospheric fractionation tower's (T-102) AGO side stripper (T-112), light diesel from the CFHT fractionation tower (T-6502), and light-cycle oil (LCO) from the FCCU fractionator tower (T-201) LCO side stripper (T-202) are processed to the DHDS feed surge drum (V-608). From the feed surge drum, the mixture is mixed with hydrogen gas and then processed through the reactor effluent/feed preheat heat exchangers and a process heater (H-601) in route to the reactor section. Exiting the reactor feed process heater (H-601), the heated feed passes through a catalytic reactor containing the hydrogenation desulfurization catalyst (R-602) where primarily sulfur is removed from the oil to form H_2S. To some extent nitrogen is also removed from the distillate. Once the distillate leaves the reactor, it then must be separated in the reactor effluent separation section.

The reactor effluent gas and un-stabilized distillate liquid are processed through a hot high-pressure separator (V-621), a cold high-pressure separator (V-601) and a cold low-pressure separator (V-602) where hydrogen gas is removed from the reactor effluent and recycled back to the reactor feed with additional makeup hydrogen gas. The reactor effluent un-stabilized distillate liquid is then processed to the DHDS stripper (T-602) which produces a sour gas (H_2S laden) product, a stabilized naphtha product, and an unstabilized diesel product.

The sour gas stream from the overhead of the stripper is processed to the sour gas amine treating unit where the H_2S is removed by absorption via a MDEA-water solution. The stabilized naphtha is processed to the naphtha hydrotreating unit feed storage tank (T-1018R). The unstabilized diesel product (stripper T-602 bottom's product) is mixed with the HCU stripper tower's (T-60006) bottom product (un-stabilized HCU distillate) and is processed to the DHDS fractionator tower (T-603) pre-heat process heater (H-603). In the DHDS fractionation section of the DHDS, additional fuel gas, light naphtha, kerosene, and ultra-low sulfur diesel/kerosene products are produced. The end products from the fractionation tower are ultra-low sulfur diesel, kerosene, and naphtha.

<u>Hydrocracking Unit (HCU)</u>
Hydrocracking is a process which catalytically cracks a wide range of petroleum fractions in the presence of hydrogen into a variety of more valuable lighter products. The HCU at the refinery is a single-stage once-through configuration. A mixture of hydrotreated gas oil from the CFHT fractionator tower (T-6502) bottoms, heavy diesel from the CFHT fractionation tower's heavy diesel side stripper (T-6503), heavy diesel from the crude unit atmospheric fractionation tower's heavy diesel side stripper (T-114), LCO from the FCCU fractionation tower's LCO side stripper (T-202) and a slip stream of heavy diesel from the DHDS fractionation tower's (T-603) bottoms product is processed through a preheat heat exchanger and then to the HCU feed surge drum (V-6701).

From the HCU feed surge drum (V-6701), the feed mixture is mixed with hydrogen gas and processed through reactor effluent/feed-preheat heat exchangers and a process heater (H-6701) in route to the reactor section. Exiting the reactor feed process heater (H-6701), the heated feed passes through a catalytic reactor (R-6701) where hydrocracking of the feedstock occurs. Once the reactor effluent exits the reactor, it is processed to the reactor effluent separation section. The reactor effluent is processed through a hot high-pressure separator (V-6702) and hot flash drum

(V-6703) where hydrogen gas is separated from the reactor effluent hydrocarbon liquid. The reactor effluent gas product is further processed through a series of vapor condensers to the HCU cold separator (V-6705) which operates under suction induced by the CFHT's compressors (C-6502) to provide recycle/makeup hydrogen to the CFHT hydrogenation desulfurization reactors (R-6501, R-6502, R-6503 & R-6504). The reactor's (R-6701) un-stabilized effluent is processed to the DHDS stripper tower (T-60006) which produces fuel gas, naphtha and a bottoms product. The stripper tower (T-60006) bottoms product serves as a partial feedstock to the DHDS fractionation tower feed process heater (H-603) as referenced in the DHDS description section. This stream is mixed with DHDS stripper tower (T-602) bottoms product in route to the DHDS fractionation tower (T-603) via the fractionation tower's pre-heat process heater H-603.

The heated effluent of process heater H-603 is processed the DHDS fractionation tower (T-603) which produces off-gas, light-naphtha, heavy naphtha, kerosene, and ULSD. The fractionators' overhead vapor is processed through condensing heat exchange coolers in route to the overhead accumulator (V-623). The overhead receivers' (V-623) off-gas is processed to the fuel gas amine treating process unit. The liquid product (light naphtha) from the overhead receiver (V-623) is processed to the NHT feed storage tank (T-1018R). A heavy naphtha product is also withdrawn from fractionation tower (T-603) and processed through product cooling heat exchangers in route to storage for use in refinery grade gasoline product blending. The kerosene (ULSD) and bottoms' product (ULSD) streams are processed through product cooling heat exchangers in route to storage for use in refinery grade ULSD product blending. The DHDS fractionation tower (T-603) is the final processing unit operation of all ULSD in the refinery.

<u>Saturated-Gas Processing Unit</u>

The saturated gas processing unit serves to separate un-stabilized light naphtha and lower-boiling petroleum intermediate fractions into fuel gas, stabilized naphtha, and refinery-grade liquefied petroleum gases [$C_{3(s)}$ and $C_{4(s)}$]. A mixture of the crude unit atmospheric fractionation tower's (T-102) light-naphtha contactor (T-113) unstabilized light naphtha product, the naphtha reforming unit naphtha stabilization debutanizer's (T-402) overhead LPG, the CFHT reactor-effluent liquid-fraction fractionation tower's (T-6502) overhead LPG, and purchased mixed-butanes is processed to the saturated-gas processing unit's feed surge drum (V-305). The feed surge drum resultant mixture is processed to a feed/product preheat heat exchanger and into an unstabilized naphtha debutanizer (T-301). A process heater (H-301) serves as the debutanizer's reboiler. The bottom product of the debutanizer is stabilized naphtha which is processed to the naphtha hydrotreating processing unit (NHT). The overhead products of the debutanizer are fuel gas and LPG ($\leq C_4$). The fuel gas is processed to the sour gas amine treating processing unit. The LPG is processed to the deethanizer (T-302) where LPG fuel-gas ($\leq C_2$) is separated from the mixture of $C_{3(s)}$ and $C_{4(s)}$ LPG. The LPG fuel gas ($\leq C_2$) is processed to the sour gas amine treating unit. The bottoms product [$C_{3(s)}$ and $C_{4(s)}$ LPG] of the deethanizer tower (T-302) is processed to the depropanizer (T-303) where the $C_{3(s)}$ and $C_{4(s)}$ are separated to produce a depropanizer overhead product (refinery grade propane transferred off-site by either tank truck or rail car) and a bottoms products [$C_{4(s)}$: n & iso]. The depropanizer bottom's product, after being mixed with the alkylation unit's isostripper's (T-904) n-butane product stream, is processed to the saturated gas processing unit's deisobutanizer (T-305). The deisobutanizer tower separates n-butane from isobutane. The n-butane resulting from the de-isobutanizer is classified as refinery grade butane and is transferred off-site by both tank truck and railcar. The isobutane product is stored on-site as a raw material feed stock to the alkylation processing unit, in addition to any purchased isobutane used as a feedstock to the alkylation processing unit. This is re-iterated in the closing portion of the description for the alkylation processing unit.

<u>Alkylation Processing Unit</u>
The purpose of this processing unit is to produce high-octane gasoline by catalytically combining light olefins with isobutane by processing the combination through an alkylation catalyst and in the presence of hydrofluoric (HF) acid. The alkylate product produced by the alkylation reactor contains branched chain paraffins that are generally the highest quality (high octane number) component in the gasoline pool. In addition to the production of high octane number constituents, the alkylate product is a clean burning product and has excellent antiknock properties. Propane and butane are byproducts of the alkylation reactor.

The mixture of light olefins processed to the alkylation process unit is the mixture of light olefins produced by the gas oil cracking reactions in the FCCU. The overhead liquid product of the FCCU's naphtha stabilization debutanizer (T-205) is processed through an alkylation feed pretreatment system consisting of an MDEA absorber, a caustic absorber, and a residual water dehydrator. The mixed olefins stream is then processed to the C_3/C_4 splitter (T951) where propane/propylene (primarily propylene) and butanes/butylenes (primarily butylene) are separated. Although butylenes are the desired feedstock to the alkylation reactor, the refinery does introduce a small portion of propylene in the feedstock as well. The majority of the propylene resulting from the overhead product of the C_3/C_4 splitter is refinery grade propylene which is delivered to consumers by railcar.

In addition to isobutane produced by the refinery's processing units, the refinery also purchases additional isobutane for use as a raw material for the alkylation process unit. Isobutane may be received at the refinery by LPG tank-trucks or railcar. The purchased isobutane is processed through the isobutane dryers to remove any residual water before being processed to the alkylation reaction section. The proportioned butylenes/isobutane mixture is processed to the alkylation reactors (R-901 & R-902) where alkylation occurs in the presence of a catalyst and HF acid. The alkylation reactor effluent is processed to the isostripper (T-904) which produces a HF rich LPG product, a refinery grade n-butane product, an alkylate product, an alkylation reactor recycle product, and an alkylation depropanizer (T-905) feed product.

The depropanizer's overhead liquid product is processed to a HF stripper tower (T-906) where the separation of HF and propane is achieved. This stripper tower reboils (by process heater H-901) the overhead product of the depropanizer to strip the HF from the LPG and accumulate the HF acid in the high pressure (HP) boot of the depropanizer overhead receiver (V-905). As withdrawn from the HP acid boot of the overhead receiver, HF acid is processed to the HF acid settlers for recycling of the acid to the alkylation reactors. The bottom's product (refinery grade propane) of the HF stripper (T-906) is processed to the propane (potassium hydroxide) KOH absorbers (T-909 & T-910) and defluorinator adsorbers (T-907 & T-908). The refinery grade propane is delivered to consumers by both railcar and tank-truck. The depropanizer bottoms product is routed to the HF regenerator (T-903) where HF is stripped from a continuous boiling mixture (CBM) of long-chain polymers created during the alkylation reaction in the presence of an alkylation reaction recycle stream.

The HF rich stream is processed to the reactors (R-901 & R-902) acid settler (V-918) where the acid may be continuously recycled to the reactors. The inventory of HF is maintained and replenished on a minimum working allowable bulk unit inventory basis addition, or alignment. The CBM is periodically withdrawn from the system's CBM polymer surge drum (V-923) and neutralized within a lime slurry pit to form residual sodium fluoride and CBM polymer, non-hazardous wastes. The acid flare collection header's vapors are processed through the KOH scrubber (T-901) and then to the alkylation process unit's acid-stream-contact-service dedicated relief flare (HI-81002).

The alkylation unit isostripper's (T-904) n-butane product stream is processed through the alkylation unit's butane KOH absorber (T- 921) and defluorinator adsorbers (T-919 & T-920). The product from the alkylation unit's absorber/adsorber treatment unit operation is mixed with the saturated gas processing unit depropanizer's (T-303) bottoms product to collectively serve as a total feedstock to saturated gas processing unit's de-isobutanizer tower (T-305). The deisobutanizer tower separates n-butane from isobutane. The n-butane resulting from the de-isobutanizer is refinery grade butane and is processed to consumers by both tank truck and railcar. The isobutane product is stored on site and is utilized as a raw material feed stock to the alkylation unit, in addition to any purchased isobutane used as a feedstock.

NHT Processing Unit

The purpose of this processing unit is to primarily remove the sulfur from stabilized naphtha that will be processed to the naphtha reforming process unit or the gasoline blending unit operation. Nitrogen is also removed by the process. The process generates sour water and ammonia (NH_3) which also must be removed prior to further processing to the naphtha reforming process. These compounds are inhibitors and/or contaminants to the naphtha reforming catalysts and reactions. The hydrotreating of sour naphtha is accomplished by processing the reactor feedstock through a hydrotreating catalyst at moderate temperature and pressure in the presence of hydrogen. Under these conditions, the sulfur and nitrogen components are converted to H_2S and NH_3, which are then removed from the reactor effluent by hot & cold single stage flash separators and distillation stripping. Removal of the sulfur and nitrogen contaminants from the naphtha provides a sweet naphtha feedstock to the naphtha reforming unit.

Heavy naphtha from the crude unit atmospheric tower (T-102), stabilized light naphtha from the saturated gas processing unit's debutanizer (T-301), naphtha from the CFHT fractionator (T-6502), and naphtha from the DHDS fractionator (T-603) are processed to the NHT feed surge drum (V-439). Hydrogen gas is added to the mixture from V-439 and the two-phase stream is processed through a series of feed/reactor-effluent preheat heat exchangers. The mixture is then proportionally processed through three hydrotreating-reactor-charge pre-heat process heaters operating in parallel (H-401A, H-401B & H-411) before entering into the naphtha hydrotreating reactors. The reactor effluent is processed through the hot and cold separators which serve to separate the high-pressure hydrogen-rich gas, sour hydrocarbon gas and liquid streams (hydrocarbon and sour water) for respective processing.

The reactor-effluent high-pressure hydrogen-rich gas is recycled to the hydrotreating reactor by compressors inducing suction on the hot high pressure separator drum. The remaining reactor-effluent gas stream from the cold separator drum is processed to the fuel gas amine treating process unit. Additionally sour water is withdrawn from the cold separator and processed to the sour water stripper processing unit. The hydrocarbon liquid stream from the cold separator is processed to NHT stripper (T-401) which separates the reactor-effluent hydrocarbon stream into additional off-gas, liquified-petroleum-gas (LPG), and unstabilized naphtha. The LPG is processed to the saturated gas processing unit's feed surge drum (V-305). The unstabilized naphtha is processed through a sulfur guard bed in route to the NHT splitter (T-403). The NHT splitter serves to stabilize the naphtha.

The overhead product (LPG) of the NHT splitter (T-403) is processed to the naphtha reforming processing unit's debutanizer overhead receiver (V-408), effectively in route to the saturated gas processing unit feed surge drum (V-305). The splitter bottom's product is processed to the naphtha reforming process unit. Process heaters H-402A and H-402B serve as the NHT splitter's (T-403) reboilers.

Naphtha Reforming Processing Unit

The purpose of this unit is to increase the octane number in naphtha to produce a higher-octane gasoline blending stock. The naphtha is reformed by using a platinum catalyst to promote aromatics formation. The splitter (T-403) bottom's product is processed to the naphtha reforming reactor #1 (R-406) pre-heat process heater (H-404) in route to the #1 reactor. The effluent of reactor R-406 is processed through reactor #1 effluent re-heat process heater (H-403) and then to naphtha reforming reactor #2 (R-407). The effluent of R-407 is processed through reactor #2 effluent re-heat process heater (H-405) and then to naphtha reforming reactor #3 (R-408). The effluent of R-408 is processed through reactor #3 effluent re-heat process heater (H-406) and then to naphtha reforming reactor #4 (R-409). Reactor #4 effluent is processed through reactor-effluent heat exchangers in route to the low pressure separator (V-405). V-405 also serves as a suction drum for hydrogen compressors in the NHT/reforming processing units which process the hydrogen gas through the absorber/pre-chiller in route to either service make-up hydrogen in the NHT or Bensat processing units or to relieve excess hydrogen to the NHT/reforming process unit's fuel gas system drum (V-412). The bottom's product of the net-gas absorber/pre-chiller is processed to the reforming process unit's debutanizer (T-402). The debutanizer stabilizes the reformed naphtha by removing off gas and LPG from the reformed naphtha product. The off-gas from the debutanizer overhead receiver is processed to the NHT/reforming process unit's fuel gas system drum (V-412). The debutanizer overhead liquid (as referenced above) is processed to the saturated gas processing unit's feed surge drum (V-305). The debutanizer bottom's product is processed to the Bensat processing unit's splitter (T-4501). A steam reboiler provides heat for the Platform Debutanizer column (T-402).

The continuous catalyst regeneration (CCR) section of the naphtha reforming processing unit enables the reforming reaction section to operate efficiently while maintaining throughput year round. The CCR continuously regenerates a circulating stream of catalyst from the reactors to burn the carbon deposits (coke) off of the catalyst. During normal operations in the reformer reaction section, catalyst activation is lowered due to coke buildup. The regeneration section continuously burns off the coke deposits formed on/in the catalyst and restores catalyst activity and selectivity to essentially those levels obtained by fresh catalyst.

<u>Bensat Unit</u>
The environmental purpose of this unit is to hydrogenate benzene into cyclohexane. The naphtha reforming process unit's debutanizer (T-402) bottoms product is processed to the Bensat process unit's reformate splitter (T-4501) via the reformate-splitter-bottoms/reformate-splitter-feed preheat heat exchanger. The splitter produces a light and heavy reformate. The heavy reformate is processed to storage to serve as a final product used as a gasoline blending stock. The light reformate produced by the reformate splitter (concentrated in benzene) is processed through fresh-feed sulfur-adsorbent beds to remove residual sulfur. Hydrogen is mixed with the sulfur-adsorbent beds effluent and the mixture is processed through reactor-feed/reactor-effluent heat exchangers in route to the Bensat benzene hydrogenation reactor (R-453). The reactor effluent is processed through the reactor-feed/reactor-effluent heat exchangers and then to the Bensat process unit's stabilizer (T-451). The stabilizer produces an off-gas which is processed to NHT/reforming processing unit's fuel gas drum (V-412) and a stabilized light naphtha product which is processed to storage to serve as a final product used as a gasoline blending stock.

<u>CAT Feed Hydrotreater (CFHT)</u>
The purpose of the FCCU feed hydrotreater (CAT Feed Hydrotreater, or CFHT) is to primarily remove sulfur compounds by a coupling of hydrogenation and hydrogenolysis and desulfurization reactions in the presence of a catalyst operating under a high hydrogen partial pressure. The fluid processed to the CFHT at the Ardmore Refinery is typically light vacuum gas oil and heavier fractions. The mechanisms of hydrotreating employed at the Ardmore Refinery include both hydrogenolysis and hydrogenation, the former being facilitated by the latter in the case of desulfurization where refractory sulfur compounds are present in the oils. The hydrogenolysis mechanism enables removal of almost all sulfur present in the form of mercaptans, sulfides, and thiophenes, as well as the majority of benzothiophenes and unsubstituted dibenzothiophenes. Co/Mo HDS catalysts are typically most effective in removing sulfur via this mechanism. At diesel sulfur levels below 100 ppmw, most of the remaining sulfur is of the dibenzothiophene family, or refractory level sulfur compounds. Sulfur removal from the 100 ppmw to the 10-15 ppmw sulfur level is, in majority, achieved through the hydrogenation mechanism. The hydrogenation mechanism requires partial hydrogenation of aromatic rings prior to initiating hydrogenolysis mechanism. The mechanism proceeds slower than the hydrogenolysis mechanism and is strongly influenced by hydrogen partial pressure. It is also subject to the free energy limitations of thermodynamic equilibrium. Ni/Mo HDS catalysts are most effective in removing sulfur via this mechanism.

The specific hydrotreating unit process unit operations of the CFHT include:

1. Transfer of feedstock from storage to the process;
2. Pre-filtering of feedstock to remove metals and sediments;
3. Addition of hydrogen gas to feedstock under pressurized conditions;
4. Preheating of combined hydrocarbon and hydrogen feedstock;
5. Modest/High temperature & pressure reaction in the presence of catalyst;
6. Reactor product cooling and condensation;
7. Fractionation/Stabilization of reactor products;
8. Off-gas process recycle and compression;
9. Off-gas sulfur cleanup for fuel and sulfur recovery;

10. Sour water processing and recovery of sulfur; and
11. Transfer of intermediates/products to storage from the process.

A mixture of LVGO and HVGO from the vacuum process unit's vacuum tower (T-106), AGO from the crude oil processing unit's atmospheric tower (T-102) AGO steam stripper (T112), asphalt from the vacuum process unit vacuum tower (T-106) bottoms, reduced crude from the crude oil process unit's atmospheric tower (T-106), and LCO from the FCCU fractionating tower's (T-201) LCO steam stripper (T-202) is processed to the pretreatment sediment-removal filters which remove metals and sediments from the mixed stream. The mixture is also processed through a series of pre-heat heat-exchangers in route to the CFHT feed surge drum (V-6501).

From the CFHT feed surge drum (V-6501), the formulated mixture is processed to the reactor(s) charge process heater (H-6501) via a multistage pump. Additionally, hydrogen produced by the steam/methane reformer is added to the mixture in route to H-6501 by two reciprocating compressors. The reactor(s) charge process heater (H-6501) effluent is processed through CFHT reactors R-6501, R-6502, R-6503, and R-6504 with intermediate additions of hydrogen (fresh & recycled) occurring through the reactor series via a steam turbine driven centrifugal hydrogen compressor. Each reactor in the reactor series contains a different type of catalyst with a very specific design intent, to include hydrogen consumption. The design intent of the catalyst in the first two reactors is to remove metals (DeMet Catalyst) contained in the feed such as nickel and vanadium. The catalyst in the third reactor is primarily designed to convert sulfur and nitrogen species into a form (H_2S and NH_3) in which they can be removed. The fourth reactor serves to remove refractory grade sulfur species to achieve ULSD specifications.

The reactors effluent is processed through four separators: hot high-pressure separator (V-6502), hot flash drum (V-6509), cold high-pressure separator (V-6503), and cold flash drum (V-6510) where hydrogen is removed from the reactor effluent, treated by an MDEA contactor (T-6501) and recycled back to the reactors with additional makeup hydrogen. The reactor hydrocarbon effluent is processed from the separators to fractionator tower pre-heat process heater H-6502. The pre-heat process heater effluent is processed to the fractionator tower (T-6502). The fractionator tower (T-6502) produces off-gas, heavy naphtha, heavy diesel, and a bottoms gas oil product.

The off-gas from the fractionator tower is processed to the amine fuel gas treating process unit. The heavy naphtha is processed to the NHT process unit's feed surge drum. The diesel product is processed to the diesel steam stripper where heavy diesel and light diesel are produced. The heavy diesel is processed to ULSD storage and product blending. The light-diesel is processed to the DHDS feed surge drum (V-608). The fractionator bottoms' product is processed to the FCCU feed surge drum (V-201).

<u>Steam-Methane Reformer (SMR) Hydrogen Production Unit</u>
Steam-methane reforming is a reaction mechanism utilized to produce hydrogen from natural gas. This is achieved in a reformer reactor which reacts steam with methane at high temperature (700-1,100 ºC) in the presence of a nickel-oxide based catalyst. Under these conditions, the steam reacts with methane to yield carbon monoxide and hydrogen. The Ardmore Refinery's SMR is capable of producing 29 MMSCFD of hydrogen product which may be utilized in hydrotreating and hydrocracking reactors. Excess hydrogen is also processed to the refinery's ballasted fuel gas

system. At full capacity and in addition to the processes inherent 600 psig steam consumption, the process unit is capable of exporting approximately 80,000 lbs of 600 psig steam to the refinery's other 600 psig consumers.

Fluid Catalytic Cracking Unit (FCCU)

The purpose of the FCCU is to covert high-boiling heavy molecular weight hydrocarbons into a mixture of gasoline-grade hydrocarbons. Competition between cracking reactions results in byproducts such as lighter hydrocarbon olefins (propylene and butylene). Typically in petroleum refineries the feedstock to a FCCU is usually that portion of the crude oil that has an initial boiling point of 340 °C or higher at atmospheric pressure and an average molecular weight ranging from about 200 to 600 or higher. This portion of crude oil is often referred to as AGO, LVGO, HVGO, asphalt, and reduced crude. Additionally, LCO, a residual oil product of the FCCU cracking reactions, is also recirculated within the FCCU via processing through the CFHT processing unit. The FCCU feed is vaporized and processed through the reactor riser where the cracking reactions occurs by contacting the vaporized feedstock (high temperature and moderate pressure) with a fluidized powdered catalyst. Coke formation on the catalyst requires continuous regeneration of the catalyst. The catalyst regeneration process at the Ardmore Refinery is a two-stage regeneration process, a partial-burn regenerator followed by a residual burn regenerator.

The FCCU operates in a heat and coke and pressure balance at all times and the balance directly impacts the operation, yields, and selectivities. Changes in the reactor section induce changes in the catalyst regeneration section and vice-versa. The major variables in the heat balance are unit configuration, equipment/hardware condition, feed properties, catalyst properties, and process conditions both in the reactor and catalyst regenerator sections. The heat balance controls the catalyst circulation rate. The combustion of coke supplies the necessary heat to heat the catalyst regeneration air, vaporize the feedstock to the reactor riser, and provide the necessary heat of reaction for cracking.

The major variables include the feed rate, feed properties (API gravity, MW, Con Carbon, average-boiling-point, and nitrogen), feed temperature, conversion, catalyst (activity, contaminant metals, and coke selective properties), reactor temperature, flue gas CO/CO_2, torch-oil, catalyst cooler duty, and stripper efficiency. Pressure balance is influenced by unit configuration, equipment/hardware condition, catalyst properties (apparent bulk density, particle-size distribution, and flowing density), and process conditions (pressures and steam and air quality and rates).

The CFHT fractionator (T-6502) bottoms product (both stored gas oil and on-run gas oil) is processed to the FCCU feed surge drum (V-201). Unit feed is processed from the surge drum through the reactor feed pre-heat process heater (H-201) in route to the reactor (R-256) riser where the feedstock comes in contact with the hot regenerated catalyst. The reentry of the hot regenerated catalyst into the reaction section's reactor riser vaporizes the gas oil feedstock upon contact. The vaporized hydrocarbon/catalyst mixture proceeds through the riser where the cracking reactions occur. The riser termination device at the end of the riser terminates the intimate contact of hydrocarbon/catalyst mixtures by disengaging the intimate contact mixture through an internal cyclone positioned in the plenum of the reactor. A coked catalyst fines level is maintained in the reactor R-256 and the superheated hydrocarbon vapor is processed out of the reactor as reactor effluent to the fractionator (T-201). The catalyst slide valves control the heat and coke balance by withdrawing the catalyst from reactor R-256 and processing the catalyst through the #1 catalyst regenerator in route to the #2 catalyst regenerator.

Induced air is supplied to both regenerators and the coke (carbon deposits) is burned off the catalyst in both regenerators. The #1 catalyst regenerator maintains a reducing atmosphere which results in a high carbon monoxide (CO) concentration and other unburned hydrocarbons. The #1 catalyst regenerator flue gas is processed to the CO boilers where the CO and unburned hydrocarbons are oxidized to CO_2. The CO boilers flue gas combines with the #2 catalyst regenerator flue gas in route to the FCCU flue gas scrubber. The flue gas scrubber stack is equipped with O_2, CO, SO_2, NO_X, and CO_2 continuous emissions monitoring systems (CEMS).

The reactor's vaporized effluent enter the FCCU reactor effluent fractionator (T-201). The fractionator produces an off-gas (methane, ethane, propane, butanes, hydrogen, ethylene, propylene, and butylenes), cracked-naphtha, LCO, and slurry. The overhead product of the fractionator is processed through a series of condensers and is processed to the fractionator overhead accumulator (V-203) where the off-gas and the cracked-naphtha are separated. The cracked-naphtha stream is processed directly to the primary absorber (T-203A).

Suction is maintained on the fractionator overhead accumulator by a wet gas compressor. The compressors' discharge is processed through condensers to the compressor discharge drum (V-205). The absorber tower bottoms' product (cracked-naphtha) is also processed to the compressor discharge drum (V-205). The liquid stream from the compressor discharge drum is processed to the deethanizer tower (T-203B). The bottoms' product of the deethanizer tower is the unstabilized cracked-naphtha stream (unstabilized FCCU gasoline) which is processed to the debutanizer (T-205).

The off-gas from the deethanizer tower is processed through vapor condensers to the compressor discharge drum (V-205). Suction is maintained on the primary absorber (T-203A) by a compressor which discharges compressed gas into the preset drum (V-206). The off-gas from preset drum is processed through the sponge absorber (T-204) which produces a reflux to the fractionator (T-201) and a sour off-gas to the fuel gas amine treating processing unit. The deethanizer (T-203B) bottoms' is processed to the debutanizer (T-205) which produces off-gas, concentrated olefins, and FCCU gasoline streams. The off-gas is processed to the fuel gas amine treating processing unit. The olefins are processed to the alkylation process unit's feed pre-treatment system (described above in the alkylation processing unit's description). The FCCU gasoline (stabilized cracked naphtha) is processed to storage for use in the final product gasoline blending pool.

Sour Water Strippers (SWS)

The purpose of the sour water strippers (#1 SWS and #2 SWS) is to remove H_2S and NH_3 from the total sour water inlet streams processed to each respective unit. The H_2S and NH_3 are stripped from the sour water feed as the water travels down the column. Rising steam strips out the H_2S and NH_3 gases. These sour water stripper gases are routed to the sulfur recovery units (#1 SRU & #2 SRU) to convert the H_2S gas stream to elemental sulfur and to destroy the NH_3 gas in the reaction section of the respective SRU.

Amine Regeneration Unit (ARU)
An aqueous Methyldiethanolamine (MDEA) solution is used in the amine sour gas treating processing unit to remove CO_2 and H_2S from sour gas by forming a weak and unstable salt. These processes take place in the fuel gas absorber and amine contactors. Once this weak and unstable amine salt solution is formed, the reaction must be reversed to regenerate the amine solution. The regeneration of the amine solution is effected in the ARU by heat.

The MDEA solution is fed to the tower from the MDEA flash drum. As the solution travels down the tower, the acid gases are stripped as the salt solution is broken down by heat, which is supplied by two steam reboilers. The regenerated MDEA solution is processed back to the regenerated MDEA surge drum where low-pressure and high-pressure service MDEA pumps process the regenerated amine solution back to the fuel gas absorber and other amine contactors/absorbers.

Sulfur Recovery Unit (SRU)(s) / w/ SCOT Process
The SRU converts the H_2S rich process gas from the ARU MDEA regenerator to liquid elemental sulfur. This process takes place in two sections: 1) H_2S is converted to elemental sulfur at high temperatures (~ 2,200 ºF) without the aid of catalytic conversion; and 2) sulfur is formed at much lower temperatures with the aid of catalytic conversion.

In section one, high thermal temperatures are maintained by using pure oxygen, which also aids in the thermal destruction of NH_3 contained in the sour water stripper gases. In section two, unconverted sulfur is processed through two or more successive catalytic stages. Each stage consists of process gas reheating, sulfur conversion over an activated alumina catalyst, and then cooling to condense and recover the sulfur formed.
In the SCOT unit operation, the tail gas from the SRU sulfur condensers is heated and mixed with a hydrogen rich reducing gas stream. The tail gas passes through a catalytic reactor where the sulfur compounds (primarily SO_2) are reconverted back to H_2S. Once the tail gas SO_2 is reduced to H_2S, the tail gas is processed to a quench system where the gases are cooled to condense water from the reactor effluent. The condensed sour water is processed to the sour water collection header. The cooled reactor effluent is processed to an absorber/stripper section where the acid gas comes in contact with an aqueous MDEA solution. The H_2S in the tail gas is absorbed by the solution. The solution is processed to the ARU where it is regenerated. The tail gas from the absorber is processed in the SRU incinerator where the residual H_2S in the tail gas is oxidized to SO_2. The SRU tail gas incinerator is equipped with a SO_2 and O_2 CEMS.

Waste Water Treatment Plant (WWTP)
The WWTP at the refinery consist of extensive processing units and a tank-farm inter-connected oily-water-sewer collection header system routed either to the influent lift station or directly to the oil water separators. The influent lift station processes its' received waste water to the oil water separator. The oil water separators serve to remove oil from supersaturated oily water. The oil-water separator effluent is processed to bioreactors for biological degradation of residual oil compounds contained the oil-water separator's effluent. The bioreactor system is equipped with a biological organism generating/incubation system which maintains optimum biological activity in the bioreactors to consume the residual oil contained in the water. The system does not utilize an activated sludge processing system but does rely on continued biodegradation, to a small extent, in aerated downstream processing/holding ponds. Aeration air and essential nutrients are

continuously supplied to the bioreactors to optimize the residual oil biodegradation process. The off-gas from the bioreactors is routed to a thermal oxidizer operating at approximately 1,600ºF or to the atmosphere.

The refinery discharges treated process water in accordance with the National Pollution Discharge Elimination System (NPDES/OKPDES) permit's general & specific discharge characteristics. The collective WWTP system is designed and permitted to treat approximately 1,100,000 gallons of process water daily. The system is designed and operated to comply with the requirements of NSPS, 40 CFR Part 60, Subpart QQQ and NESHAP, 40 CFR Part 63, Subpart FF. The refinery complies with the 6BQ option of Subpart FF.

<u>Product Movement Operations & Storage Tank Farm</u>

Stored raw materials, intermediate products, and refinery grade finished products include the storage of sweet and sour crude oils, sour naphtha, reformed naphtha, catalytically cracked naphtha, hydrocracked naphtha, alkylate, regular gasoline, premium gasoline, ethanol, kerosene, distillate, ULSD, olefins, isobutane, n-butane, propane, butylenes, propylene, vacuum gas oils (LVGO & HVGO), atmospheric gas oil, reduced crude, asphalts, polymer modified asphalt, slurry, LCO, molten sulfur, slop oil, oily-water, and sour water.

The Planning and Economics, Operations, and Product Movement/Blending Departments at the refinery schedule, effect, and implement transfers of materials within the refinery's custody, throughout the refinery's processing units, and out of the refinery's custody. Crude oil is received into the refinery, in majority, by pipeline. Small quantities of crude may be received from local production oil wells by tank truck.

The Operations Department processes the crude oil at a rate and assay determined by the Planning and Economics Department. The Operations Department adjusts each processing unit’s specifications to achieve the product quality specifications. The products produced by each processing unit are transferred into the Product Movement/Blending Department’s custody. The Planning and Economics Department determines the necessary movements/transfers of the available products in the production pool to effect refinery grade end products meeting consumer and/or regulation product specifications. The Product Movement/Blending Department receives it’s instructions to hold, store, blend, and transfer materials into and out the refinery's custody. Products are transferred out of the refinery by pipelines, tank trucks, and railcars.

<u>Polymer Modified Asphalt (PMA) Unit</u>

The PMA Unit blends high molecular weight polymer into asphalt base stocks for modification of straight run asphalt into finished PMA products. The asphalt flux and base stocks are proportioned by specific product recipe and measured through mass flow meters prior to introduction into the processing skid where they are blended into a base stock/flux mixture in the PMA mixing tank. The base stock/flux mixture is then blended with polymer via a high-shear mill before being processed into one of two, heated and agitated, reaction tanks. After the initial reaction, the base stock/flux mixture proceeds to the acidification tank where it is mixed with phosphoric acid. After the reaction is complete, the product is either stored in one of three sales tanks or pumped directly to the black oil transfer trucks at the loading docks. Storage vessels are heated by a hot oil that is processed through heat-exchange coils in each tank.

Refinery Steam Production

The refinery maintains steam availability to consumers by five (5) saturated steam production headers: 600, 150, 70, 50 and 45 psig. The 150 psig through 45 psig production headers are maintained by the non-condensing service portions of the 600 psig to 150 psi to 70 psig to 50 psig to 45 psig letdown valves in addition to steam produced by 150 psig, 70 psig, 50 psig and 45 psig sources located throughout various processing units.

The 600 psig steam is produced by the SMR reactor's effluent cooling (REC) heat exchangers, the FCCU CO boilers, the vacuum unit tower bottom's (VTB) product cooling heat exchanger, and the #2 SRU sulfur reactor effluent waste heat boiler (WHB) heat exchanger. The nominal 600 psig saturated steam production capacities for the SMR REC, FCCU CO boilers, Vacuum Unit VTB, and #2 SRU WHB are: 140,000 lbs/hr, 240,000 lbs/hr, 13,000 lbs/hr and 70,000 lbs/hr, respectively, or approximately 0.5 MMlbs/hr. The 600 psig saturated steam service at the refinery is primarily necessary to serve in the capacity of drive potential for steam turbines to include an induced air blower in the SMR, a compressor in the CFHT, pumps in the SMR, and two 9 MW electricity generators in the FCCU. The 600 psig steam processed through these sources are processed in such a way that the steam processed through the sources result to saturated 150 psig steam rather than condensed steam. As a result, approximately all 600 pisg steam contributes to the 150 psig steam header.

In addition to the 600 psig steam to 150 psig letdown, additional 150 psig steam generating sources include three utility boilers(B-801, B-802 & B-803), two waste-heat boilers in the crude oil processing unit pre-heat process heater's flue gas heat recovery system (H-104 & H-105), two product effluent cooling heat exchangers [E-139 (B & C)] located in the vacuum processing unit (vacuum tower bottoms product cooling heat exchangers), one waste heat boiler located in the crude oil processing unit atmospheric fractionation tower (T-102) slopwax withdraw product cooling heat exchange system, one waste heat boiler (B-801) located the #1 SRU reactor effluent cooling system, one waste heat boiler (E-251) located in the FCCU #2 regenerator's flue gas waste heat recovery system, two product cooling heat exchangers [E-203 (A & B)] located in the FCCU processing unit, one waste heat boiler located in the crude oil processing unit atmospheric fractionation tower (T-102) AGO withdraw product cooling heat exchange system, three product cooling heat exchangers (E-621, E-622 & E-625) located in the DHDS processing unit, and two NHT/naphtha-reforming process heaters (H-404/H-405 and H-403). These 150 psig steam generation sources are capable of producing approximately 0.6 MMlbs/hr of 150 psig steam.

The 70 psig steam generation sources includes the CFHT fractionator (T-6502) light-diesel draw product cooling heat exchanger (E-6524), the CFHT fractionator (T-6502) light-diesel reflux cooling heat exchanger (E-6511), and the CFHT fractionator (T-6502) bottoms (gas oil feed to FCCU) cooling heat exchanger (E-6519). These 70 psig steam generation sources are capable of producing approximately 42.0 Mlbs/hr of 70 psig steam. The 70 psig steam header is also supplemented by a 150 psig to 70 psig letdown valve.

The 50 psig steam generation sources includes the #2 SRU reaction furnace/SCOT-reactor waste-heat recovery cooling heat exchanger (E-5602), and the #2 SRU SCOT-reactor waste-heat recovery cooling heat exchanger (E-5603). These 50 psig steam generation sources are capable of producing approximately 15.0 Mlbs/hr of 50 psig steam. The 50 psig steam header is also supplemented by a 150 psig to 50 psig letdown valve.

The 45 psig steam generation sources include the #1 SRU sulfur-condensation waste-heat recovery cooling heat exchangers [E-503 (A, B & C)]. These 45 psig steam generation sources are capable of producing approximately 6.0 Mlbs/hr of 45 psig steam. The 45 psig steam header is also supplemented by a 150 psig to 45 psig letdown valve.

The total saturated steam production capability of the refinery's steam generation sources is approximately 1.2 MMlbs/hr.

Gasoline Desulfurization Unit

On October 16, 2014, the DEQ issued Permit No. 2012-1523-TVR (M-1), a minor modification to the Title V operation permit. This modification authorized the installation and operation a Gasoline Desulfurization Unit (GDU) to reduce the sulfur content of gasoline produced by the Fluidized Catalytic Cracking Unit (FCCU) located at the facility. The GDU has a capacity of 20.5 thousand barrels per day (MBPD).

The GDU is used to desulfurize FCCU gasoline (naphtha) and, potentially, naphtha from the SAT Gas Unit via selective hydrotreating while maintaining high octane in the gasoline. The GDU comprises the following sections:

- Selective Hydrogenation Unit (SHU) Reactor Section,
- Splitter Section,
- Hydrodesulfurization (HDS) Reaction Section,
- Amine Absorber Section, and
- Stabilizer Section.

The purpose of the SHU Reactor Section is to hydrogenate diolefins (reduce carbon-carbon double bonds to single bonds) in the gasoline feed stream (from the FCCU) to prevent gumming and to prevent pressure drop problems in the HDS reaction section of the GDU. The gasoline feed from the FCCU is initially mixed with make-up/recycle hydrogen gas prior to being preheated by the SHU reactor feed preheater and other heat exchangers, using reactor effluent from the SHU reactor and splitter before entering the SHU reactor. The SHU reactor effluent is then routed to the splitter section of the GDU for further processing.

The SHU reactor effluent is then cooled via heat exchanger and sent to the high pressure separator (the splitter column). The liquid hydrocarbon effluent stream from the high pressure separator is sent to the HDS reaction section and the sour water stream is sent to the sour water stripper (SWS) units. The vapor phase stream from the high pressure separator is routed to the refinery fuel gas amine treating unit.

The liquid hydrocarbon effluent from the high pressure separator is mixed with hydrogen-rich recycle gas and makeup hydrogen and preheated in heat exchangers and in the fuel-gas fired HDS reactor heater prior to being routed to the HDS reactor. The HDS reactor removes the sulfur from the organic compounds by a chemical reaction that converts a sulfur-containing organic compound into a non-sulfur-containing compound and H_2S. This chemical reaction is known as hydrogenation.

The HDS reactor effluent is routed through a series of heat exchangers and a condenser to cool the stream before the effluent is sent to the HDS cold separator drum. The vapor effluent from the separator drum is treated in the amine absorber knockout drum and in the high pressure (HP) amine absorber tower to remove H_2S. The "clean" vapor effluent is then primarily re-routed back to the HDS reaction section as the hydrogen-rich recycle gas. Any vapor effluent not used as recycle gas is routed to the refinery fuel gas treating unit. The rich amine from the HP amine absorber tower is routed back to the amine recovery unit (ARU) for regeneration.

The hydrocarbon liquid effluent from the HDS cold separator drum is routed to the stabilizer section as feed. The sour water stream from the HDS cold separator drum is routed to the SWS units.

A stabilizer is used to strip additional H_2S and light ends from the hydrotreated product from the HDS reaction section. The treated product from the stabilizer is cooled via heat exchange and routed to gasoline storage. The stabilizer overhead passes through condensers to an overhead receiver. Receiver hydrocarbon liquid product is recycled back to the stabilizer as the reflux stream. The receiver sour water stream is sent to the SWS units. The vapor phase stream from the receiver flows to a low pressure amine scrubber where H_2S is removed from the gas.

SECTION III. EVALUATION OF PROJECTS

This section addresses changes authorized by this minor modification to the Title V operating permit. Because this permit incorporates numerous individual projects, this section begins with an overall evaluation whether the projects may be considered individually or whether they should be aggregated for the purposes of major New Source Review (NSR) applicability. Following that analysis, the evaluation of each individual project will be structured as follows.

(a) Detailed process description for activities involved in the project.
(b) Description of affected equipment associated with the particular project.
(c) Emissions associated with the project.
(d) Prevention of Significant Deterioration (PSD) evaluation of the project.
(e) NSR project aggregation analysis for the project.
(f) Evaluation of applicability of New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) to the project.
(g) Analysis of the project with regard to Air Quality Division requirements under Oklahoma Administrative Code (OAC) 252:100-8, which is also referred to as Subchapter 8.

Evaluation of the Projects for NSR Project Aggregation

Project aggregation is when two or more physical or operational changes at a source are combined into a single "project" for purposes of major NSR applicability. EPA's primary focus in formulating criteria for "project aggregation" has been to ensure that major NSR is not circumvented through some artificial separation of activities that are reasonably seen as a single project. Based on current EPA policy [see "Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR): Aggregation; Reconsideration," 83 FR 57324-57333, November 15, 2018], physical and/or operational changes at a source should be aggregated into a single project for consideration of major NSR applicability when those changes are "substantially related." In determining whether the changes are substantially related, EPA provided the following guidance:

(1) A source need not group changes based on timing alone;
(2) Changes are not required to be aggregated simply because they support the plant's overall basic purpose; and
(3) EPA will presume that changes separated by three or more years are not substantially related unless the specifics of the activities rebut that presumption.

Valero evaluated projects undertaken since the issuance of their most recent Title V operating permit modification [Permit No. 2012-1523-TVR (M-1), issued on October 16, 2014] to confirm that each project may be considered separately without circumventing any NSR permitting requirements. Valero confirmed that each project meets the following criteria:

(1) Each proposed project is capable of surviving economically at the plant without the support of an additional proposed project, and none of the proposed projects are dependent on any other proposed project to be economically viable.
(2) None of the proposed projects are dependent on any other proposed project to be technically viable. Specifically, and without limitation:
    (a) None of the proposed projects rely exclusively or are dependent on any other proposed project to provide raw materials as a necessary input.
    (b) None of the proposed projects rely exclusively or are dependent on any other proposed project to release an intermediate project.

The following table identifies projects that have been subjected to this analysis.

Projects Evaluated for the Project Aggregation Analysis

Permit Number *1	Project Description
2012-1523-C (M-2)	Application submitted on September 2, 2014. The application requested a construction permit to authorize the installation of a new 285.3 MMBTUH boiler. The permit was issued on April 22, 2015.
2012-1523-C (M-4)	Application submitted on February 29, 2016. The application requested a construction permit to incorporate requirements from a consent decree (Civil Action No. SA-05-CA-0569) into the permit. No new emissions units or modifications were authorized by this permitting action. This construction permit provided the basis on which these conditions agreed to in the consent decree may be incorporated into the Title V operating permit.
2012-1523-C (M-5)	This permit was issued as an administrative amendment to Permit No. 2012-1523-C (M-4). Valero requested a slight change in specific condition language to conform with the requirements of the consent decree. The administrative amendment was issued on June 13, 2016.

Projects Evaluated for the Project Aggregation Analysis

Permit Number [*1]	**Project Description**
2012-1523-TVR (M-6)	The application was submitted on May 31, 2016. Valero requested a minor modification to incorporate an Alternative Monitoring Plan for the Fluidized Catalytic Cracking Unit (FCCU) Flue Gas Scrubber, to incorporate VOC and PM emissions estimates for two existing cooling water towers, to change the classification of a diesel-driven water pump (from an insignificant activity to EUG 40), and to address a number of minor administrative issues (corrections and updates to permit language).
2012-1523-C (M-7)	This permit was issued as an administrative amendment to Permit No. 2012-1523-C (M-5). Valero requested a slight change in specific condition language to conform with the requirements of the consent decree. The administrative amendment was issued on June 30, 2016.
2012-1523-TVR (M-8)	The application was submitted on January 9, 2017. Valero requested a minor modification to incorporate the requirements for operation of a 600 psig, 285.3 MMBtu/hr steam production boiler into the Title V operating permit. Construction of this emission unit was authorized by Permit No. 2012-1523-C (M-2). This application also requested a number of administrative changes, including the consolidation of multiple leak detection a repair (LDAR) emission units into a single emissions unit under Emission Unit Group (EUG) 31.
2012-1523-TVR (M-9)	The application was submitted on August 18, 2017. Valero requested a minor modification to allow an additional cell to an existing cooling tower and to redistribute the loads to two existing cooling towers.
2012-1523-AD (M-10)	The application was submitted on January 30, 2018. Valero requested an applicability determination to confirm that they could rebuild Tank T-1018 under the current permit with or without performing a minor modification to the Title V operating permit. The determination was issued on August 11, 2020.
2012-1523-TVR (M-11)	The application was submitted on January 30, 2018. Valero requested a minor modification to authorize the replacement of an existing process heater (H-407) with a new steam reboiler which uses steam from an existing 600 pound steam boiler (B-15001).
2012-1523-TVR (M-12)	The application was submitted on January 30, 2018. Valero requested a minor modification to authorize the installation of a new emergency generator engine for a new administration building.
2012-1523-TVR (M-13)	The application was submitted on July 3, 2018. Valero requested a minor modification to authorize installation of replacement feed filters and a new filter tray in the catalytic feed hydrotreater (CFHT) reactor R-6502 (R-2).
2012-1523-TVR (M-14)	The application was submitted on September 5, 2019. Valero requested a minor modification to authorize an increase the flow rate of supplementary fuel gas (also referred to as “sweep gas”) to the Alky Flare, which is designated as Emission Unit (EU) HI-81002, in Emissions Unit Group (EUG) 14.

[*1] The project associated with Application No. 2012-1523-TVR (M-3) was cancelled.

Construction Permit No. 2012-1523-C (M-2)

A. Description of the Project and Associated Process Changes

The application requested authorization to construct a new 600 psig steam production boiler with a maximum heat input of 285.3 MMBtu/hr (million British thermal units per hour). The boiler was equipped with low-NO_X burners and a CEMS for NO_X. The project also resulted in incremental associated emissions increases from a number of existing units.

The boiler has a peak steam-generating capacity of 210,000 pounds per hour of 600 psig steam. Installation of the new boiler allowed for supply of steam to a variety of processes, but the primary use of the new boiler was expected to be during refinery-wide turnarounds where the CO boilers and FCCU scrubbers are taken out of service.

In addition to the new boiler, the permit authorized the following changes:

- A typo was corrected for EUG 20. Engine P-1806 is actually a diesel-fired engine (fired by ultra-low sulfur diesel) and it should not be required to be fired by natural gas.
- In EUG 31, the LDAR 100 emission unit category was formerly broken into four different subcategories. In this permit, those categories were combined. This did not result in a change in regulatory status for any emission unit in that EUG.

Valero requested a limit to keep project emission increases below the PSD threshold and the permit underwent Tier II review. The permit was issued on April 22, 2015. Because this project was authorized in a permit that has already been issued, this project evaluation is intended as a simple overview, rather than an in-depth analysis.

B. Equipment Associated with the Project

EUG 13B Combustion Units
Subject to NSPS, Subpart Ja & OAC 252:100-19

EU	Point	Description	MMBTUH	Const. Date
B-15001	P240	Boiler	285.3	January 2015

C. Emissions Associated with the Project

To evaluate emissions associated with the project, for each emissions unit (EU), the emission increases were based on the difference between the “potential emissions” (PTE) or “projected actual emissions” (PAE) and the “baseline actual emissions” (BAE). Existing EU may use either their PAE or PTE to determine if a significant emissions increase of a regulated NSR pollutant will result from a proposed project. Owners or operators who use the PTE for existing units are not subject to the recordkeeping requirements in OAC 252:100-8-36.2(c). New emissions units must use their PTE and BAE values are set to zero.

New Unit – Potential to Emit

For the new 285.3-MMBtu/hr boiler installation project, Valero calculated potential emissions from the new unit (Boiler B-15001) using emission factors, process rates, and operating assumptions as discussed following. For this unit, BAE values are equal to zero.

The potential emissions increase in NO_X was estimated using a NO_X emission factor of 0.045 lb/MMBtu for the ultra low-NO_X burners and an annual average firing rate of 177.63 MMBtu/hr. Potential NO_X emissions are limited by a specific condition, requiring that the unit be equipped with a continuous emissions monitoring system (CEMS) and that NO_X emissions be calculated every month and limited to 35.01 TPY (12-month rolling total) to ensure that the project does not result in a significant emission increase under OAC 252:100-8-30(b). The NO_X emissions are also be limited to 0.10 lb/MMBtu (30-day rolling average) under NSPS, Subpart Db. As long as the NO_X emissions comply with the limit set by NSPS, the monitored emission rate may fluctuate up or down as long as the computed 12-month rolling total NO_X emissions do not exceed 35.01 TPY.

Potential emissions for other pollutants were estimated using the maximum firing capacity of the unit (285.3 MMBtu/hr), a typical fuel heat rate (918 Btu/scf HHV), and continuous firing (8,760 hours/year). Considering the limits on NO_X emissions, these assumptions are conservative. The following emission factors were used for the additional pollutants: CO: 0.045 lb/MMBtu (vendor guarantees), VOC: 5.5 lb/MMscf [AP-42(7/98), Table 1.4-2], SO_2: 9.98 lb/MMscf (derived from NSPS, Subpart Ja emission standards for H_2S in refinery fuel gas – 60 ppmv annual average and a 100% conversion of H_2S to SO_2), $PM_{10}/PM_{2.5}$: 7.6 lb/MMscf [AP-42(7/98), Table 1.4-2]. Greenhouse gas (GHG) emissions were calculated using a refinery gas fuel combustion factor which includes the production of N_2O (with the appropriate global warming potential) as well as CO_2.

Emissions for the New 285.3-MMBtu/hr Boiler

Pollutant	Emission Factor	Hourly Emissions (lb/hr)	Annual Emissions (TPY)
NO_X [1]	0.045 lb/MMBtu	12.84	35.01
CO	0.045 lb/MMBtu	12.84	56.23
$PM_{2.5}$ [1]	7.6 lb/MMscf	2.36	6.44
SO_2 [2]	9.98 lb/MMscf	8.37	13.59
VOC	5.5 lb/MMscf	1.71	7.49
CO_2e [3]	120,000 lb/MMscf	----	163,686

[1] Hourly emissions for NO_X and $PM_{2.5}$ are based on the maximum firing rate of 285.3 MMBtu/hr. Annual emissions for NO_X and $PM_{2.5}$ are based on a maximum annual average firing rate of 177.63 MMBtu/hr. Potential emissions for all other pollutants were based on the full 285.3-MMBtu/hr firing rate.

[2] Hourly emissions for SO_2 are based on an hourly emission rate of 26.93 lb/MMscf which was derived from the three-hour maximum allowable H_2S concentration set by NSPS, Subpart Ja: 162 ppmv. Annual emissions for SO_2 are based on the emission factor shown (derived from the annual limit as discussed in the preceding paragraph).

[3] The emission factor shown in the table is for CO_2. Emissions of CH_4 and N_2O were also estimated and used to calculate the CO_2e annual emission value shown in this table.

Existing Units – Associated Emissions Increases

The installation of the new boiler was not expected to increase the throughput of any existing unit, nor was this project expected to debottleneck any operation. To confirm that the project would not result in a significant emissions increase of any regulated NSR pollutant, the applicant calculated associated emissions increases for all existing units using the actual-to-potential test as described in OAC 252:100-8-30. In addition, Valero made use of the concept of *demand growth* to exclude emissions "that an existing unit could have accommodated" (from the definition of "projected actual emissions") to address emissions that the refinery was physically and legally capable of accommodating prior to implementation of the project. (See 40 CFR 52.21(b)(41)(ii) and OAC 252:100-8-31.) The approach is described in some detail in the memorandum for Permit No. 2012-1523-C (M-2) and those details will not be repeated here.

D. PSD Evaluation

The facility is an existing major stationary source as defined in OAC 252:100-8-31. An evaluation was performed to determine whether the project constitutes a major modification as defined in OAC 252:100-8-30(b).

Project Emission Increases

Emission Units	NO_X	CO	$PM_{2.5}$	SO_2	VOC	CO_{2e}
	TPY	TPY	TPY	TPY	TPY	TPY
Potential to Emit for the New Unit: EUG 13-B (B-15001) [1]	**35.01**	**56.23**	**6.44**	**13.59**	**7.49**	**163,686**
Associated Emissions Increases for Existing Units [2]	**4.98**	**17.84**	**0.47**	**0.53**	**19.09**	**---** [3]
Project Emission Increases	**39.99**	**74.07**	**6.91**	**14.12**	**26.58**	**>163,686**
Significance Levels	**40**	**100**	**15**	**40**	**40**	**75,000**

1 Potential emissions for the new unit as limited by specific conditions included in this construction permit.
2 Unit-by-unit associated emissions increases are presented in the previous table.
3 For this permitting action, the associated emissions increases for CO_2e are not relevant to the analysis.

The project emissions increases for the new boiler project were below the significance levels for all regulated pollutants, except for greenhouse gases (GHG). Because the project will result in no significant emissions increase for any other pollutant, the project did not trigger PSD and the increase in GHG emissions does not itself trigger PSD or require the applicant to perform a BACT analysis. Associated emissions increases were based on incremental demand increases; the permittee is required to keep records of project emissions increases in accordance with OAC 252:100-36.2(c).

E. Evaluation of the Project for NSR Project Aggregation

Valero has stated that installation of the new unit will not result in debottlenecking of any facility operations. Project aggregation was addressed earlier in this section. The possible interaction between this project and the project authorized under minor modification 2012-1523-TVR (M-11) is addressed in the discussion of that project.

F. Evaluation of the Project for NSPS and NESHAP Applicability

The new boiler is subject to NSPS, Subparts Db and Ja and NESHAP, Subpart DDDDD.

NSPS, Subpart Db, Industrial-Commercial-Institutional Steam Generating Units. This subpart affects steam generating units with a heat input capacity greater than 100 MMBTUH and that commence construction, modification, or reconstruction after June 9, 1989. The new boiler (B-15001) is subject to this subpart. The boiler fires only refinery gas and natural gas. This is significant, in terms of regulatory applicability, because §60.40b(b)(1) through (4) include requirements specific to boilers which fire coal and/or oil. Because boiler B-15001 fires neither coal nor oil, the requirements identified in these subparagraphs (including the requirement to comply with SO_2 standards under Subpart D) do not apply to the new unit. In accordance with §60.40b(c), because the unit is subject to SO_2 standards under NSPS, Subpart Ja, the unit must comply with those requirements as well as applicable PM and NO_X standards under this subpart. Because the unit will not fire coal, oil, wood, or municipal solid waste, it is not subject to any PM standards included in §60.43b. Manufacturer's data confirm that the new boiler will exhibit a *low heat release rate* as defined in §60.42b ($\leq$ 70,000 Btu/hr•ft^3); the heat release rate is the "steam generating unit design heat input capacity (in MW or Btu/hr) divided by the furnace volume…" Under this subpart, the boiler is subject to standards for nitrogen oxides (NO_X) applicable to units which fire natural gas or refinery gas. When firing natural gas, the new boiler is subject to the NO_X limits (expressed as NO_2) presented in §60.44b of this subpart: 0.10 lb/MMBtu (30-day rolling average). The refinery gas that is also used to fuel the boiler does not meet the definition of *natural gas* in this subpart, because it will contain less than 70% methane and the gross caloric value of the refinery gas will likely be less than 910 Btu per dry scf. However, the refinery gas does meet the definition of *byproduct/waste*: "any liquid or gaseous substance produced at chemical manufacturing plants, petroleum refineries, or pulp and paper mills (except natural gas, distillate oil, or residual oil) and combusted in a steam generating unit for heat recovery or for disposal. Gaseous substances with carbon dioxide (CO_2) levels greater than 50 percent or carbon monoxide levels greater than 10 percent are not byproduct/waste for the purpose of this subpart." As such, the new boiler is still required to meet a NO_X standard (expressed as NO_2) of 0.10 lb/MMBtu (30-day rolling average) in accordance with §60.44b(e). The applicant has elected to install a continuous emissions monitoring system (CEMS) to monitor compliance with these requirements. All applicable requirements have been incorporated into the permit.

NSPS, Subpart Ja, Petroleum Refineries. This subpart applies to the following affected facilities in petroleum refineries: FCCU, fluid coking units (FCU), delayed coking units, fuel gas combustion devices (including process heaters), flares, and sulfur recovery plants. Except for flares and delayed coking units, this subpart only applies to those affected facilities that began construction, modification, or reconstruction after May 14, 2007.

Fuel Gas Combustion Devices

Under this subpart, *fuel gas combustion device* is defined as "any equipment, such as process heaters and boilers, used to combust fuel gas. For the purposes of this subpart, *fuel gas combustion device* does not include flares or facilities in which gases are combusted to produce sulfur or sulfuric acid." The new boiler (B-15001) is subject to this subpart.

EU	Description	MMBTUH	Const. Date
B-15001	Boiler	285.3	1st Quarter 2015

The new unit clearly meets the definition of *fuel gas combustion device* and it is subject to requirements applicable to such units. Further, this subpart establishes NO_X emission limits for units which also meet the definition of *process heater* and which have a rated capacity greater than 40 MMBTUH. This subpart defines *process heater* as "an enclosed combustion device used to transfer heat indirectly to process stream materials (liquids, gases, or solids) or to a heat transfer material for use in a process unit instead of steam." The new boiler does not meet this definition, because it does not transfer heat to process stream materials; rather, it is used to produce steam. Therefore, it is not be subject to the NO_X emission limits under this subpart.

For fuel gas combustion devices, this subpart establishes a fuel gas H_2S limitation for all fuel gas combustion devices which commence construction, reconstruction, or modification after May 14, 2007. The fuel gas H_2S limits are set at 162 ppmv determined hourly on a 3-hour rolling average basis and 60 ppmv determined daily on a 365 successive calendar day rolling average basis. Subpart Ja requires the fuel gas H_2S concentration to be continuously monitored and recorded. (It should be noted that a fuel gas CEMS is already in operation at the facility.) In addition, §60.103a(c)(2) requires the permittee to report excess SO_2 emissions which are, essentially, emissions ≥ 500 lb more than allowable if the fuel gas H_2S concentration limits were abided by. If the facility experiences such an excess emission event, it is required to perform a root cause analysis and perform corrective actions. All applicable requirements have been incorporated into the permit.

NESHAP, Subpart DDDDD, Industrial, Commercial and Institutional Boilers and Process Heaters. On January 31, 2013, the EPA took final action on its reconsideration of certain issues in the emission standards for the control of HAP from industrial, commercial, and institutional boilers and process heaters at major sources of HAP. The compliance dates for the rule are January 31, 2016, for existing sources and, January 31, 2013, or upon startup, whichever is later, for new sources. The new boiler is a new unit which is subject to this subpart.

New Boilers/Process Heaters > 10 MMBTUH

EU	Point	Description	MMBTUH	Const. Date
B-15001	P240	Boiler	285.3	2015

This unit is designed to burn gas 1 fuels. *Unit(s) designed to burn gas 1 subcategory* includes any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels. The unit is equipped with a continuous oxygen trim system that will maintain an optimum air to fuel ratio. As such, it is required to complete a tune-up every five years as specified in §63.7540(a)(12). Units in the gas 1 subcategory will conduct these tune-ups as a work practice for all regulated emissions under Subpart DDDDD. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory are not subject to the emission limits in Tables 1 and 2 or 11 through 13 of Subpart DDDDD, or the operating limits in Table 4 of Subpart DDDDD. All applicable requirements have been incorporated into the permit.

G. Analysis of Applicable Requirements under Subchapter 8

The facility is an existing major source of criteria pollutants and HAPs that operates under a Title V (Part 70) operating permit governed by OAC 252:100-8 (Subchapter 8). Subchapter 8 establishes requirements for facilities to obtain construction permits and operating permit modifications to authorize changes to the facility.

Significant Modification

A facility is required to obtain a permit for a significant modification if the change meets the criteria specified in OAC 252:100-8-7.2(b)(2)(A). Because Valero requested a federally enforceable emissions cap to avoid classification as a modification under PSD, the project was determined to be a significant modification. As such, it underwent Tier II public review.

Application for Minor Modification No. 2012-1523-TVR (M-3)

Valero requested a minor modification to allow changes to be made in the recovered oil processing at the refinery. The project was cancelled and the application was withdrawn.

Construction Permit No. 2012-1523-C (M-4)

Valero requested a construction permit to incorporate requirements from a consent decree (Civil Action No. SA-05-CA-0569) into the permit. No new emissions units or modifications were authorized by this permitting action. This construction permit provided the basis on which these conditions agreed to in the consent decree may be incorporated into the Title V operating permit. This application underwent Tier I review.

Construction Permit No. 2012-1523-C (M-5)

This permit was issued as an administrative amendment to Permit No. 2012-1523-C (M-4).

Application for Minor Modification No. 2012-1523-TVR (M-6)

A. Description of the Project and Associated Process Changes

Valero requested the incorporation of the EPA-approved Alternative Monitoring Plan (AMP) for the FCCU Flue Gas Scrubber (EU FGS-200) into permit specific conditions and the removal of existing language regarding the operation of the Continuous Opacity Monitoring Systems (COMS) used to monitor opacity at this emission unit. The AMP was approved by EPA Region 6 on April 28, 2016, and it establishes parametric monitoring requirements of the wet gas scrubber (WGS) in lieu of the requirement to operate a COMS system to monitor opacity at the FCCU. The approved AMP included the following requirements:

- Minimum liquid-to-gas ratio (L/G) – 10.5 lb-mol/lb-mol
- Minimum water pressure to the quench/spray tower nozzles – 40.0 psig
- Minimum pressure drop across the Agglo-filtering module – 4.3 in. H_2O (This parameter proved problematic)

Subsequently, Valero experienced difficulties with the operating parameters established in the AMP. Due to fluctuations in ambient weather conditions (moisture, pressure, and temperature), it was difficult to maintain the pressure drop across the Agglo-filtering module at the magnitude incorporated in the AMP. Valero notified AQD and EPA Region 6 of their request to adjust the requirements of the AMP prior to performing additional testing. Additional testing was performed on December 13-14, 2016, and the test results demonstrated that the facility could demonstrate compliance with the PM limits using a lower pressure drop (1.1 in. H_2O).

Cooling Tower Emissions

The current Title V permit identifies four existing cooling towers under the Trivial Activities (TA) section in accordance with OAC 252:100-8-2. However, all four of the cooling towers are also included in the specific conditions under EUGs 42A, 42B, 42C, and 42D. These are grandfathered units with no emission limits. Valero is adding emissions estimates for the Ceramic Cooling Tower (EUG 42B) and the Alky Cooling Tower (EUG 42C) to the permit memorandum. These emissions do not represent a physical change or a change in the method of operation. In addition, they do not constitute an emissions increase, although incorporation of these emissions will result an increase in calculated facility-wide emissions.

Reclassification of Firewater Pump Engine

The Valero Ardmore Refinery uses an existing firewater pump and engine which historically qualified as an Insignificant Activity (ISA) in accordance with OAC 252:100-8-2. Valero is requesting the addition of this source to existing EUG 40. Valero intends to use this engine in other services and is seeking authorization to operate the engine in normal service, rather than as an emergency engine.

Administrative changes

The applicant requested the following administrative changes to the permit.

EU Group	Description of Change Requested	Justification for Change
EUG 2	Remove T-1008 and T-1135 from the description and the table.	These tanks have reached the end of their useful life and have been removed.
EUG 5	Remove T-1111 from the description and the table.	This tank reached the end of its useful life and has been out of service for several years.

EU Group	Description of Change Requested	Justification for Change
EUG 5	Change the emissions points for EUs T-210003, T-210004, T-210005, T-210006, T-210007, and T-210008 from P26, P27, P-28, P29, P30, and P31 to P186.	Emissions form PMA storage tanks T-210003, T-210004, T-210005, T-210006, T-210007, and T-210008 are routed to and released from Emissions Inventory (Redbud) Seq. No. 158, PMA caustic scrubber. All of these tanks are linked together in a "loop" that is educted and recirculated (forced) through the scrubber (EUG 39 P186).
EUG 15	Remove the superscript "1" from the SO_2 lb/hr column for HI-501 and HI-5602.	Adds clarity. (The superscript : "1" refers to the averaging time for the NOx limits. The "2" refers to the averaging time for the SO_2 limits. The "1" superscripts for the SO_2 limits represented an error.
EUG 16	Change "d" to: "All off-gases from the asphalt blowstill shall be *either* combusted by a properly operated and maintained incinerator, *routed to the fuel gas recovery system, or routed to the #1 SRU*. [OAC 252:100-8-6(a)(1)]"	Normally the blowstill emissions are controlled by an incinerator; however, the off gas can be routed to the fuel gas recovery system or the #1 SRU. Each of these options constitutes control.
EUG 16	Change "e" to: "The stack flue gas temperature of the incinerator of EU HI-801 shall not drop below 1,260°F based on a three hour average *while the incinerator is used to control emissions from any of the following: the asphalt blowstill, the MEROX De-Sulfide Settler (V-732), or the Alkylate/Gasoline Railcar Loading Station (RCALOAD 900)*."	V-732 is the Merox Settler. The Blowstill Incinerator is the typical control device for this off gas; however, the off gas can be directed to the flare header and ultimately refinery fuel gas. It can also go to the #1 SRU. When the stream is routed elsewhere and blown asphalt is not being made, Valero requests the flexibility to shut down the incinerator.
EUG 16	Change "j" to "Emissions from the MEROX disulfide settler (V-732) shall be vented to EU HI-801, HI-501, *or the flare gas recovery system*."	V-732 is the Merox Settler. The Blowstill Incinerator is the typical control device for this off gas. However, the off gas can be directed to the flare header where the flare gas recovery system will send it to refinery fuel gas. It can also go to the #1 SRU.
EUG 18	Change "g" to "The FCCU No. 1 Regenerator and the FCCU No. 2 Regenerator shall be operated with ~~internal~~ cyclones to reduce emissions of PM_{10}."	Please remove the word "internal." The word internal is too specific and not required. Specifying the cyclone to control PM_{10} is that is required to meet the rule. Both internal and external cyclones are in current operation.
EUG 19	Change all references to B-253 to B-253A.	Valero's documentation lists this emission unit as B-253A. This unit was labeled incorrectly in a previous permit and Valero wishes to make this administrative change.
EUG 19	Change all references to B-254 to B-253B.	Valero's documentation lists this emission unit as B-253B. This unit was labeled incorrectly in a previous permit and Valero wishes to make this administrative change.

EU Group	Description of Change Requested	Justification for Change
EUG 19	Change "k" to "The refinery shall use *a fuel gas flow meter to monitor* fuel gas and air flow rates to the CO boiler(s), fuel gas Fd factors, as determined using fuel gas analyses, in conjunction with the FGS NOx, SO_2, CO, and O_2 CEM(s) data to determine compliance with the above emission limits."	Valero contends that this is clearer that the fuel gas flow meter is used.
EUG 20	Valero requests that a descriptor be added for each of the engines listed in this group. Please add a column to the table with the following descriptions: EEQ-8801: Wastewater Generator EEQ-80001: Central Control Room Generator P1806: Fire Pond Water Pump P1807A: HF Alky Emergency Deluge (East) P1807B: HF Alky Emergency Deluge (Middle) P1807C: HF Alky Emergency Deluge (West) EG1880-01: Guard House Generator EG1880-02: Admin Building Generator	These changes will add clarity.
EUG 23	Change "a" to read: "EU SSP-520 shall be vented to the SRU incinerator or the *inlet* of the SRU at all times."	Replace the word "input" with "inlet" to add clarity.

In addition, Valero requested additional administrative changes on reviewing a preliminary draft of the M-6 permit. These changes are summarized below.

EUG 5 Emissions Unit Table – Request to combine six tanks into a single emission unit. EUG 5 identifies applicable requirements for a collection of cone roof (CR) Group 2 storage vessels which are subject to NESHAP, Subpart LLLLL. Six of the tanks are configured to allow liquids to flow freely between the tanks. In addition, the vent lines from each of these six tanks are tied into a common manifold that routes vapors to the V-210001 polymer modified asphalt (PMA) Vent Gas Scrubber, P-26. Valero provided a process flow diagram to confirm this configuration. Due to this common configuration, vapors flowing from any tank in this system are shared with the vapors from the other tanks, making the system of six tanks act as a single unit from an operational standpoint.

Valero has requested that these six tanks (T-210003, T-210004, T-210005, T-210006, T-210007, and T-210008) be considered a single combined source with regard to compliance with NESHAP, Subpart LLLLL. Prior to this change, Valero would be required to report a single potential compliance deviation occurring at the PMA Vent Gas Scrubber as six separate, identical violations, one for each tank in the system. Incorporating the six tanks into a single emission unit is a more accurate depiction of the equipment configuration.

The following table shows this change.

New Combined EU for Six Tanks in EUG 5

EU	Tank	Point	Roof Type	Barrels
T-1102	T-1102	P19	Cone	75,786
T-1113	T-1113	P21	Cone	131,005
T-1118	T-1118	P22	Cone	79,742
T-1151	T-1151	P23	Cone	206,979
T-100149	T-100149	P24	Cone	35,847
T-100150	T-100150	P25	Cone	35,847
P-26 (includes the group of tanks indicated, which are configured to allow liquids to flow freely between the tanks and which have vent lines from each tank tied into a common manifold that routes vapors to the V-210001 PMA Vent Gas Scrubber, P-26)	T-210003	P186	Cone	3,021
	T-210004		Cone	6,526
	T-210005		Cone	6,526
	T-210006		Cone	10,197
	T-210007		Cone	10,197
	T-210008		Cone	11,715

EUG 16, Paragraph d – Request for clarification. Valero requested a revision to clarify the requirement for "properly operated and maintained incinerator," to include a more specific, measurable compliance demonstration. The new language is underlined below.

d. All off-gases from the asphalt blowstill shall be either combusted by a properly operated and maintained incinerator (i.e., operated at a 3-hour average combustion zone temperature greater than 1,260°F), routed to the fuel gas recovery system, or routed to the #1 SRU. [OAC 252:100-8-6(a)(1)]

EUG 16, Paragraph e – Request for clarification. Valero requested a revision to clarify the requirement for the operation of the asphalt blowstill incinerator. The new language is underlined below.

e. The stack flue gas temperature of the incinerator of EU HI-801 shall not drop below 1,260 °F based on a three hour average, during periods in which V-732 is venting to HI-801 and while the incinerator is used to control emissions from any of the following: the asphalt blowstill, the MEROX De-Sulfide Settler (V-732), or the Alkylate/Gasoline Railcar Loading Station (RCALOAD 900). [OAC 252:100-8-6(a)(1)]

EUG 18, Paragraph a(i) – Request to reflect installation of SO_2 CEMS. Valero requested a revision to update the specific condition to show that an SO_2 CEMS has been installed, certified, calibrated, maintained, and operated on EU GGS-200, as required under the Valero Consent Decree and in accordance with EUG 18 a(i). The new language is underlined in a(i) as follows.

a. EU FGS-200 shall be equipped with continuous emissions monitoring systems (CEMS) for determining and recording NO_X, CO, and SO_2 emissions corrected to dry basis and 0% O_2. The CEMS shall meet the applicable performance specifications of 40 CFR Part 60, Appendix B. [OAC 252:100-8-6(a)(3) & 100-43]

i. With respect to the NO_X, SO_2, and O_2 CEMS, the source shall install, certify, calibrate, maintain and operate them in accordance with the provisions of …

EUG 19, Emission Unit Table – Request to correct an error. Units B-253A and B-253B emit from point P70 (Belco Scrubber), rather than from points P71 and P72. The corrected language is shown below.

EU	Point	Description	MMBTUH
B-253A	~~P71~~ P70	CO Boiler	144.0
B-253B	~~P72~~ P70	Boiler/CO Boiler	144.0

EUG 19, Paragraph k – Valero requested that the term "fuel gas" be removed from the term "fuel gas flow meter," to accurately represent that air flow rates will be measured by separate flow meters than those used to measure fuel gas flows. Valero requested that the language in the Specific Condition for EUG 19, paragraph k be revised as follows:

k. The refinery shall use a ~~fuel gas~~ flow meter to monitor fuel gas and air flow rates to the CO boiler(s), fuel gas Fd factors, as determined using fuel gas analyses, in conjunction with the FGS NO_X, SO_2, CO, and O_2 CEM(s) data to determine compliance with the above emission limits.

[OAC 252:100-8-6(a)(3) & 100-43]

EUG 32 – Valero noted that the language in EUG 32 differentiates regulatory applicability for equipment in EUG 32 between equipment in HAP service (i.e., >5% by weight HAP) as being subject to NESHAP, Subpart CC (paragraph a) and equipment not in HAP service (i.e., <5% by weight HAP) being subject to NSPS, Subpart GGGa (paragraph b). Valero has determined that, as modified existing sources, the equipment included in EUG 32 is subject ***only*** to NSPS, Subpart GGGa, regardless of HAP content. This is due to the overlap provisions in NESHAP, Subpart CC. Valero requested that the specific condition be modified to read as follows.

EUG 32 Fugitive Equipment Leaks Subject to LDAR Program~~s~~ NSPS, Subpart GGGa ~~& NESHAP, Subpart CC~~. Fugitive equipment items do not have specific limitations, except to comply with the applicable LDAR programs.

EU	Point	Description
LDAR 260	F100	Area 260 - Gasoline Desulfurization Unit
LDAR 300	F54	Area 300 - Sat Gas Unit
LDAR 450	F55	Area 450 - BenSat Unit

a. All equipment in VOC service (contacting >10% by weight VOC) shall comply with the requirements of NSPS 40 CFR Part 60, Subpart GGGa including but not limited to:

[40 CFR §§ 60.590a-593a]

i. § 60.592a Standards (a-e);
ii. § 60.593a Exceptions (a-e).

EUG 40, Emission Unit Table – The make/model designations for EUs P850A and P850B include typographical errors that should be corrected as follows:

EUG 40 Stationary Reciprocating Internal Combustion Engines (RICE) Subject to NSPS, Subpart IIII and/or NESHAP, Subpart ZZZZ: EU P850A, P850B, P850C, P850D, P850E, and FWPE-1.

EU	Point	Make/Model	KW (HP)	Applicable Subparts
P850A	P187	Deutz ~~F4L914~~ F4914	61.5 (82.5)	IIII, ZZZZ
P850B	P188	Deutz ~~F4L912~~ F4912	54 (72.5)	ZZZZ
P850C	P189	John Deere 4045DF 270B	60 (80)	ZZZZ
P850D	P190	John Deere 4045TF 280B	63 (84)	IIII, ZZZZ
P850E	P191	John Deere 4045TF 275B	86 (115)	ZZZZ
FWPE-1	P226	Caterpillar 3406C	345 (460)	ZZZZ

In addition, during internal review, AQD permitting staff noticed that two of the engines (EU P850A and EU P850E) were incorrectly identified in the specific conditions for EUG 40 as being subject to NSPS, Subpart IIII. This error has been corrected. It should be noted that, in Section VIII, Federal Regulations, the discussion of units subject to NSPS, Subpart IIII, properly stated that neither of these engines is subject.

B. Equipment Associated with the Project

This project did not include the installation of new equipment or the modification of any existing equipment.

Valero did request reclassification of an emergency firewater pump engine to a normal use engine.

EUG 40 WWTP Transfer Pump's ICE
Subject to NSPS, Subpart IIII and/or NESHAP, Subpart ZZZZ

EU	Point	Make/Model	KW (HP)	Serial #	Const. Date
FWPE-1	P226	Caterpillar 3406C	345 (460)	3ER07868	2002

Valero is adding emissions estimates for the Ceramic Cooling Tower (EUG 42B) and the Alky Cooling Tower (EUG 42C) to the permit memorandum. These emissions do not represent a physical change or a change in the method of operation. In addition, they do not constitute an emissions increase, although incorporation of these emissions will result an increase in calculated facility-wide emissions.

EUG 42B Ceramic Induced Draft Cooling Tower
1,200-hp, 273 MMBTUH, 20,000 GPM, Heat Exchangers W/HAP Concentration >5%, W/Pressure > Cooling Water Pressure, & Subject to NESHAP, Subpart CC

EU	Point	Heat Exchangers
C-1501	P193	E-10043 - Vent Gas Condenser
		E-10044 - Vent Gas Condenser
		E-101 – Fractionator Heavy Naphtha Product Cooler
		E-111A – Fractionator Light Naphtha Condenser
		E-111B – Fractionator Light Naphtha Condenser
		E-111C – Fractionator Light Naphtha Condenser
		E-111D – Fractionator Light Naphtha Condenser
		E-113A – Fractionator Light Naphtha Condenser
		E-113B – Fractionator Light Naphtha Condenser
		E-113C – Fractionator Light Naphtha Condenser
		E-113D – Fractionator Light Naphtha Condenser
		E-116A – Fractionator Heavy Naphtha Product Cooler
		E-116B – Fractionator Heavy Naphtha Product Cooler
		E-116C – Fractionator Heavy Naphtha Product Cooler
		E-116D – Fractionator Heavy Naphtha Product Cooler
		E-304A – Debutanizer Naphtha Product Cooler
		E-304B – Debutanizer Naphtha Product Cooler
		E-304C – Debutanizer Naphtha Product Cooler
		E-403 – Light Naphtha Condenser
		E-405A – Splitter Naphtha Product Cooler
		E-411A – Naphtha Reformer Reactor Product Cooler
		E-411B – Naphtha Reformer Reactor Product Cooler
		E-416 – Debutanizer Heavy Reformate Product Cooler
		E-418 – Debutanizer Light Reformate Product Cooler

EUG 42C Alkylation Induced Draft Cooling Tower
700-hp, 248 MMBTUH, 16,000 GPM, Heat Exchangers W/HAP Concentration >5% W/Pressure > Cooling Water Pressure, & Subject to NESHAP, Subpart CC

EU	Point	Heat Exchangers
C-150005	P194	E-903A – Alkylate Product Cooler
		E-903B – Alkylate Product Cooler
		E-907A – Reactor Alkylate Recycle Cooler
		E-907B – Reactor Alkylate Recycle Cooler
		E-907C – Reactor Alkylate Recycle Cooler
		E-907D – Reactor Alkylate Recycle Cooler
		R-901 – Alkylation Reactor/Heat Exchanger
		R-902 – Alkylation Reactor/Heat Exchanger

C. Emissions Associated with the Project

Emergency Firewater Pump Reclassification

Valero is requesting reclassification of an emergency firewater pump engine to a normal use engine. To determine whether this change in classification (the project) is a major modification under Prevention of Significant Deterioration (PSD) regulations [OAC 252:100-8-30], Valero submitted an evaluation of project emission increases. As a conservative estimate, to determine whether the project resulted in a significant emissions increase, Valero elected to perform the actual-to-potential test for projects that only involve existing emissions units [OAC 252:100-8-30(b)(6)]. Further, Valero used zero baseline actual emissions. Potential emissions from engine FWPE-1, a 460 hp Caterpillar 3406C fire pump engine are presented in the following table. Hourly and annual actual emissions are also included in this table, but those emissions are not relevant to the PSD analysis.

Emissions from EU FWPE-1, EUG 40

Pollutant	Emission Factor (lb/hp•hr)	Emissions			
		Hourly (lb/hr)	Actual Annual (TPY)	Potential (TPY)	PSD Significance Level (TPY)
NOx	0.01711	7.87	4.72	34.47	40
CO	0.00333	1.53	0.92	6.71	100
VOC	0.0002	0.09	0.06	0.40	40
PM-10	0.00094	0.43	0.26	1.89	15
PM-2.5	0.00094	0.43	0.26	1.89	10
SO_2	0.00205	0.94	0.57	4.13	40
Formaldehyde	0.00015	0.07	0.04	0.30	--

Potential emissions are based on continuous operation (8,784 hours per year).
Emission factors for NO_X, CO, PM-10, and VOCs are based on manufacturer's data. The emission factor for SO_2 was obtained from AP-42 (10/1996), Section 3.3

There are no associated emissions increases for this project. Project emissions increases are below PSD significance levels.

Cooling Tower Emissions

The cooling towers were previously identified as trivial activities even though all four cooling towers were included in the specific conditions under EUGs 42A, 42B, 42C, and 42D. These are grandfathered units with no emission limits. Valero is adding emissions estimates for the Ceramic Cooling Tower (EUG 42B) and the Alky Cooling Tower (EUG 42C) to the permit memorandum. These emissions do not represent a physical change or a change in the method of operation. In addition, they do not constitute an emissions increase, although incorporation of these emissions will result an apparent increase in calculated facility-wide emissions.

PM_{10} and VOC Emissions from EUG 42B and 42C

		PM_{10}		VOC	
EU	**Description**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
C-1501	Ceramic Induced Draft Cooling Tower	6.61	28.95	126.90	16.66
C-150005	Alkylation Induced Draft Colling Tower	5.83	25.54	100.48	38.93
Totals		**12.44**	**54.50**	**228.38**	**55.58**

Emissions from the cooling towers are based on a circulation rate of 20,000 gallons per minute (gpm) for the Ceramic Cooling Tower (C-1501) and 16,000 gpm for the Alky Cooling Tower (C-150005).

PM_{10} emissions were estimated using an empirically derived drift factor (2,632 lb H_2O drift/10^6 gal. cooling tower circulation rate), a total dissolved solids (TDS) concentration of 2,093 ppmw (Ceramic Tower) and 2,308 ppmw (Alky Tower), and assuming all solids are emitted as PM_{10}.

Annual VOC emissions were estimated using annual average strippable VOC concentrations of 0.38 ppmw (Ceramic Tower) and 1.11 ppmw (Alky Tower).

Hourly VOC emissions were estimated using maximum hourly strippable VOC concentrations of 12.68 ppmw (Ceramic Tower) and 12.55 ppmw (Alky Tower).

Strippable VOC emissions were estimated a mass-balance approach for a simulated air stripper with a 20:1 air to liquids volumetric flow ratio. Annual emission rates were computed using the average return air stripped VOC concentrations for each tower (28.5 ppmv for the Ceramic Cooling Tower and 84.25 ppmv for the Alky Cooling Tower), and the average return sample temperature (69.3ºF for the Ceramic Cooling Tower and 73.38ºF for the Alky Cooling Tower). Hourly emission rates were computed using the maximum return air stripped VOC concentrations for each tower (1,000 ppmv for each tower), and the maximum return sample temperature (95.0ºF for the Ceramic Cooling Tower and 101.0ºF for the Alky Cooling Tower).

It should be noted that many of the values in this table were subsequently updated during the evaluation of the M-9 application.

D. PSD Evaluation

The facility is an existing major stationary source as defined in OAC 252:100-8-31. An evaluation was performed to determine whether the project constitutes a major modification as defined in OAC 252:100-8-30(b).

Emergency Firewater Pump Reclassification

Because the emissions estimate was performed exclusively for PSD evaluation, this analysis is not repeated here.

Cooling Tower Emissions

The incorporation of emissions estimates into the memorandum is not associated with any physical change or change in the method of operation. This is not a modification under PSD, nor does it need to be included with the engine status change.

E. Evaluation of the Project for NSR Project Aggregation

Project aggregation issues were addressed for ***all*** of the projects discussed in this permitting action earlier in Section III. This project (M-6) raised no additional project aggregation issues that need to be addressed in greater depth.

F. Evaluation of the Project for NSPS and NESHAP Applicability

This project did not involve the installation of any new emission units or the modification of any existing units.

G. Analysis of Applicable Requirements under Subchapter 8

Significant Modification

A facility is required to obtain a permit for a significant modification if the change meets the criteria specified in OAC 252:100-8-7.2(b)(2)(A):

(i) Involve any significant changes in existing monitoring requirements in the permit;

This permitting action incorporates an EPA approved Alternative Monitoring Plan (AMP) for the FCCU Flue Gas Scrubber (EU FGS-200) into permit specific conditions and the removal of existing language regarding the operation of the Continuous Opacity Monitoring Systems (COMS) used to monitor opacity at this emission unit. The AMP was approved by EPA Region 6 on April 28, 2016 and it establishes parametric monitoring requirements of the wet gas scrubber (WGS) in lieu of the requirement to operate a COMS system to monitor opacity at the FCCU.

Incorporation of these changes is not considered to be a significant permit modification.

The change in status of the firewater pump engine will not result in any significant changes in existing monitoring requirements.

The inclusion of emission estimates for the cooling towers will not result in any change in monitoring requirements.

The administrative changes and corrections are not significant permit modifications.

(ii) Relax any reporting or recordkeeping requirements.

The changes are not considered to be a relaxation.

(iii) Change any permit condition that is required to be based on a case-by-case determination of an emission limitation or other standard, on a source-specific determination of ambient impacts, or on a visibility or increment analysis;

The specific condition changes do not modify conditions based on a case-by-case determination or an existing emission limitation or other standard, a source-specific determination of ambient impacts, or a visibility increment analysis.

(iv) Seek to establish or change a permit term or condition for which there is no corresponding underlying applicable requirement or state-only requirement which the

source has assumed to avoid some other applicable requirement or state-only requirement to which the source would otherwise be subject. Such terms and conditions include:

(I) A federally enforceable emissions cap assumed to avoid classification as a modification under any provision of Title I;

There are no changes in federally enforceable emissions caps.

(II) An alternative emissions limit approved pursuant to regulations promulgated under section 112(i)(5) of the Act; and

The will be no establishment or change in any emissions limit.

(v) Are modifications under any provision of Title I of the Act; and,

New Source Performance Standards (NSPS):
Under section 111 of the Act, the term “modification” means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted. Explanation: there are no physical changes associated with this project. The change in classification of the firewater pump engine is not a modification under NSPS.

National Emission Standards for Hazardous Air Pollutants (NESHAP):
Under section 112 of the Act, the term "modification" means any physical change in, or change in the method of operation of, a major source which increases the actual emissions of any hazardous air pollutant emitted by such source by more than a de minimis amount or which results in the emission of any hazardous air pollutant not previously emitted by more than a de minimis amount. Rulemaking-to-date implements these requirements for construction and reconstruction only. Explanation: there are no physical changes associated with this project. The change in classification of the firewater pump engine will not change the requirements under NESHAP, Subpart ZZZZ.

Prevention of Significant Deterioration (PSD):
Major modification means:
Any physical change in or change in the method of operation of a major stationary source that would result in a significant emissions increase of a regulated NSR pollutant and a significant net emissions increase of that pollutant from the major stationary source is a major modification. Explanation: The reclassification of the firewater pump engine will not result in a significant emissions increase of a regulated NSR pollutant so it is not a major modification.

The requested changes are not modifications under any provision of Title I of the Act.

(vi) Do not qualify as minor permit modifications or administrative amendments.

The project is a minor modification.

<u>Minor Modification</u>

A minor modification is a revision to the permit that cannot be accomplished under an administrative amendment [OAC 252:100-8-7.2(a)] and is not a significant modification. The project cannot be accomplished under an administrative amendment. It is a minor modification.

Construction Permit No. 2012-1523-C (M-7)

This permit was issued as an administrative amendment to Permit No. 2012-1523-C (M-5).

<u>New Specific Condition Language</u>

- Language was added to the requirements for EUG 18.a: "With respect to the NO_X and O_2 CEMS, the source shall install, certify, calibrate, maintain and operate them in accordance with the provisions of 40 CFR §60.13 which are applicable only to CEMS (excluding those provisions applicable only to continuous opacity monitoring systems) and Part 60, Appendices A and F, and the applicable performance specification test of 40 CFR Part 60, Appendix B. With respect to 40 CFR Part 60 Appendix F, in lieu of the requirements of 40 CFR Part 60, Appendix F §§5.1.1, 5.1.3 and 5.1.4, the source must conduct either a RAA or a RATA on each CEMS at least once every three (3) years. The source must also conduct CGA each calendar quarter during which a RAA or a RATA is not performed."

- The following language replaced the previous language for EUG 18.i.i.A: "One (1) pound per 1,000 pounds of coke burned (front half only according to Method 5B or 5F, as appropriate), measured as a one-hour average over three performance test runs."

This permit also incorporated the updated Title V Standard Conditions.

Application for Minor Modification No. 2012-1523-TVR (M-8)

A. Description of the Project and Associated Process Changes

Valero requested a minor modification to incorporate the requirements for operation of the 600 psig, 285.3 MMBtu/hr steam production boiler into the Title V operating permit. Construction of this emission unit was authorized by Permit No. 2012-1523-C (M-2). The boiler is equipped with low-NO_X burners and a CEMS for NO_X. This application also requested a number of administrative changes, including the consolidation of multiple LDAR emission units into a single emissions unit under EUG 31. Most of these changes were authorized by the construction permit and their incorporation into the operating permit was requested by this permitting action.

Because the construction permit underwent Tier II public review, and because the additional changes requested are considered to be minor modifications under Oklahoma Administrative Code (OAC) 252:100-8-7.2(b)(1), this permitting action is classified as Tier I.

In addition to the new boiler, this permitting action incorporates the following changes:

- A typo was corrected for EUG 20. Engine P-1806 is actually a diesel-fired engine (fired by ultra-low sulfur diesel) and it should not be required to be fired by natural gas.
- In EUG 31, the LDAR 100 emission unit category was formerly broken into four different subcategories. In this permit, those categories were combined. This did not result in a change in regulatory status for any emission unit in that EUG.

B. Equipment Associated with the Project

EUG 13B Combustion Units
Subject to NSPS, Subpart Ja & OAC 252:100-19

EU	Point	Description	MMBTUH	Const. Date
B-15001	P240	Boiler	285.3	January 2015

C. Emissions Associated with the Project

Project emissions were discussed above in associated with Permit No. 2012-1523-C (M-2) and in more detail in that permit which was issued on April 22, 2015. Those details were not changed in this permitting action, which merely requested incorporation of the requirements into the Title V operating permit.

D. PSD Evaluation

The PSD evaluation remains unchanged from the description provided above for Permit No. 2012-1523-C (M-2).

E. Evaluation of the Project for NSR Project Aggregation

Valero has stated that installation of the new unit will not result in debottlenecking of any facility operations. Project aggregation was addressed earlier in this section. The possible interaction between this project and the project authorized under minor modification 2012-1523-TVR (M-11) is addressed in the discussion of that project.

F. Evaluation of the Project for NSPS and NESHAP Applicability

The new boiler is subject to NSPS, Subparts Db and Ja and NESHAP, Subpart DDDDD. A discussion of applicability of NSPS and NESHAP requirements was presented above for Permit No. 2012-1523-C (M-2) and will not be repeated here.

G. Analysis of Applicable Requirements under Subchapter 8

The facility is an existing major source of criteria pollutants and HAPs that operates under a Title V (Part 70) operating permit governed by OAC 252:100-8 (Subchapter 8). Subchapter 8 establishes requirements for facilities to obtain construction permits and operating permit modifications to authorize changes to the facility.

Significant Modification

A facility is required to obtain a permit for a significant modification if the change meets the criteria specified in OAC 252:100-8-7.2(b)(2)(A). Because Valero requested a federally enforceable emissions cap to avoid classification as a modification under PSD, Permit No. 2012-1523-C (M-2) project was determined to be a significant modification and it underwent Tier II public review. Valero requested Permit No. No. 2012-1523-TVR (M-8) to authorize incorporation of those requirements into the Title V operating permit and to authorize administrative changes (corrections) to two specific conditions.

Minor Modification

A minor modification is a revision to the permit that cannot be accomplished under an administrative amendment [OAC 252:100-8-7.2(a)] and is not a significant modification. Incorporation of the applicable requirements from Permit No. 2012-1523-C (M-2) and the correction specific condition language is authorized under a Tier I minor modification.

Application for Minor Modification No. 2012-1523-TVR (M-9)

A. Description of the Project and Associated Process Changes

Valero requested a minor modification to allow an additional cell to be added to an existing cooling tower and to redistribute the loads to two existing cooling towers.

Valero currently has four cooling towers, one of which has been idled:

(1) Cat Feed Hydrotreater (CHT) Cooling Tower (EUG 42A)
(2) Ceramic Cooling Tower (EUG 42B) [Currently Idled]
(3) Alky Cooling Tower (EUG 42C)
(4) STG Cooling Tower (EUG 42D)

Previously these cooling towers were classified as trivial activities, but they were also identified as emission units subject to specific conditions due to the applicability of NESHAP, Subpart CC. They were grandfathered units without emission limits. Valero applied for a previous minor modification [2012-1523-TVR (M-6)] to incorporate emission estimates in the memorandum and to remove the units from the listing as trivial activities, because emission units are not eligible for that classification if they are subject to a state or federal applicable requirement.

Under this modification, Valero requested authorization to reroute a portion of the existing pump alignments and piping interconnections from the Ceramic Cooling Tower (EUG 42B) to the STG Cooling Tower (EUG 42D). Valero is removing the two existing pumps from EUG 42D and replacing them with three pumps [P-1505A, P-1505B, and P-1505D]. A new cell will be added to EUG 42D. EUG 42B will be left with only on pump, P-1505C. In addition, Valero is requesting that the list of heat exchangers currently represented in the permit as being associated with EUG 42B be added, in their entirety, to EUG 42D, since the piping changes will result in that equipment also being routed to EUG 42D. As a result of these changes, the Ceramic Cooling Tower has been taking out of operational service and has been idled.

The following table highlights the changes.

Cooling Tower Pump Alignment Summary – Minor Mod M-9

	Existing Scenario		Future Scenario	
	Pump	Capacity (gpm) [1]	Pump	Capacity (gpm) [1]
Ceramic Cooling Tower CT-1501, EUG 42B	P-1505A	8,800	--	--
	P-1505B	8,500	--	--
	P-1505C	8,500	P-1505C	8,500
	Total	25,800	Total	8,500
STG Cooling Tower CT-15006, EUG 42D	P-80100	10,932	P-1505D	8,500
	P-80101	10,932	P-1505A	8,800
	--	--	P-1505B	8,500
	Total	21,864	Total	25,800
Total Flow, both Cooling Towers	--	**47,664**	--	**34,300**

[1] gpm = gallons per minute

B. Equipment Associated with the Project

EUG 42B Ceramic Induced Draft Cooling Tower
1,200-hp, 273 MMBTUH, 17,600 GPM, Heat Exchangers W/HAP Concentration >5%, W/Pressure > Cooling Water Pressure, & Subject to NESHAP, Subpart CC

EU	Point	Heat Exchangers
C-1501	P193	E-10043 - Vent Gas Condenser
		E-10044 - Vent Gas Condenser
		E-101 – Fractionator Heavy Naphtha Product Cooler
		E-111A – Fractionator Light Naphtha Condenser
		E-111B – Fractionator Light Naphtha Condenser
		E-111C – Fractionator Light Naphtha Condenser
		E-111D – Fractionator Light Naphtha Condenser
		E-113A – Fractionator Light Naphtha Condenser
		E-113B – Fractionator Light Naphtha Condenser
		E-113C – Fractionator Light Naphtha Condenser
		E-113D – Fractionator Light Naphtha Condenser
		E-116A – Fractionator Heavy Naphtha Product Cooler
		E-116B – Fractionator Heavy Naphtha Product Cooler
		E-116C – Fractionator Heavy Naphtha Product Cooler
		E-116D – Fractionator Heavy Naphtha Product Cooler

EU	Point	Heat Exchangers
		E-304A – Debutanizer Naphtha Product Cooler
		E-304B – Debutanizer Naphtha Product Cooler
		E-304C – Debutanizer Naphtha Product Cooler
		E-403 – Light Naphtha Condenser
		E-405A – Splitter Naphtha Product Cooler
		E-411A – Naphtha Reformer Reactor Product Cooler
		E-411B – Naphtha Reformer Reactor Product Cooler
		E-416 – Debutanizer Heavy Reformate Product Cooler
		E-418 – Debutanizer Light Reformate Product Cooler

EUG 42D STG Induced Draft Cooling Tower
600-hp, 214 MMBTUH, 21,500 GPM, Heat Exchangers W/HAP Concentration >5%, W/Pressure > Cooling Water Pressure, & Subject to NESHAP, Subpart CC

EU	Point	Heat Exchangers
C-150006	P195	E-81004 – FGR Naphtha Slop Product Cooler
		E-10043 - Vent Gas Condenser [1]
		E-10044 - Vent Gas Condenser
		E-101 – Fractionator Heavy Naphtha Product Cooler
		E-111A – Fractionator Light Naphtha Condenser
		E-111B – Fractionator Light Naphtha Condenser
		E-111C – Fractionator Light Naphtha Condenser
		E-111D – Fractionator Light Naphtha Condenser
		E-113A – Fractionator Light Naphtha Condenser
		E-113B – Fractionator Light Naphtha Condenser
		E-113C – Fractionator Light Naphtha Condenser
		E-113D – Fractionator Light Naphtha Condenser
		E-116A – Fractionator Heavy Naphtha Product Cooler
		E-116B – Fractionator Heavy Naphtha Product Cooler
		E-116C – Fractionator Heavy Naphtha Product Cooler
		E-116D – Fractionator Heavy Naphtha Product Cooler
		E-304A – Debutanizer Naphtha Product Cooler
		E-304B – Debutanizer Naphtha Product Cooler
		E-304C – Debutanizer Naphtha Product Cooler
		E-403 – Light Naphtha Condenser
		E-405A – Splitter Naphtha Product Cooler
		E-411A – Naphtha Reformer Reactor Product Cooler
		E-411B – Naphtha Reformer Reactor Product Cooler
		E-416 – Debutanizer Heavy Reformate Product Cooler
		E-418 – Debutanizer Light Reformate Product Cooler

[1] Exchangers E-10043 through E-418 are added as a result of this modification.

C. Emissions Associated with the Project

To evaluate emissions associated with the project, for each emissions unit, the emission increases were based on the difference between the "potential emissions" (PTE) or "projected actual emissions" (PAE) and the "baseline actual emissions" (BAE). Existing EU may use either their PAE or PTE to determine if a significant emissions increase of a regulated NSR pollutant will result from a proposed project. Owners or operators who use the PTE for existing units are not subject to the recordkeeping requirements in OAC 252:100-8-36.2(c). New emissions units must use their PTE and BAE values are set to zero. This project only involves existing units.

To estimate emission changes associated with the project, Valero calculated baseline actual emissions and projected actual emissions for and PM-10 and VOCs. Other pollutant emissions are negligible.

Baseline and Future Activity

Emission Unit	Baseline Period	Baseline Activity (gal/min)	Projected Activity (gal/min)
Ceramic Cooling Tower	January 2013 – December 2014	17,776	18,372
STG Colling Tower	January 2013 – December 2014	9,671	6,624

PM-10 and VOC Emissions Associated with the Project

		PM-10 (TPY)		VOC (TPY)	
EU	**Description**	**BAE**	**PAE**	**BAE**	**PAE**
C-1501	Ceramic Induced Draft Cooling Tower	25.73	26.60	14.81	15.30
C-150006	STG Cooling Tower	15.44	10.57	23.53	16.12
Totals		**41.17**	**37.17**	**38.33**	**31.42**

Emissions from the cooling towers are based on a circulation rates provided in the activity table.

PM-2.5 emissions were estimated using an empirically derived drift factor (2,632 lb H_2O drift/10^6 gal. cooling tower circulation rate), a total dissolved solids (TDS) concentration of 2,093 ppmw (Ceramic Tower) and 2,308 ppmw (STG Tower), and assuming all solids are emitted as PM-10.

Annual VOC emissions were estimated using annual average strippable VOC concentrations of 0.38 ppmw (Ceramic Tower) and 1.11 ppmw (STG Tower).

Strippable VOC emissions were estimated a mass-balance approach for a simulated air stripper with a 20:1 air to liquids volumetric flow ratio. Annual emission rates were computed using the average return air stripped VOC concentrations for each tower (28.5 ppmv for the Ceramic Cooling Tower and 84.25 ppmv for the STG Cooling Tower), and the average return sample temperature (69.3°F for the Ceramic Cooling Tower and 73.38°F for the STG Tower).

This project will result in no potential emissions increases for the cooling towers. Emissions will decrease below the calculated quantities shown in minor modification M-6.

D. PSD Evaluation

The facility is an existing major stationary source as defined in OAC 252:100-8-31. An evaluation was performed to determine whether the project constitutes a major modification as defined in OAC 252:100-8-30(b).

Project Emission Increases

Emission Units	**PM-10**	**VOC**
	TPY	**TPY**
Potential to Emit for the New Unit: None [1]	**0.00**	**0.00**
Associated Emissions Increases for Existing Units [2]	**<0.00**	**<0.00**
Project Emission Increases	**<0.00**	**<0.00**
Significance Levels	**15**	**40**

1 No new units were constructed under this modification.
2 Emissions for each unit are shown in the previous table.

The project emissions increases for the project were below the significance levels for all regulated pollutants. The permittee is required to keep records of project emissions increases in accordance with OAC 252:100-36.2(c).

E. Evaluation of the Project for NSR Project Aggregation

Project aggregation issues were addressed for all of the projects discussed in this permitting action earlier in Section III. This project (M-9) raised no additional project aggregation issues that need to be addressed in greater depth.

F. Evaluation of the Project for NSPS and NESHAP Applicability

This project will result in no changes in NSPS or NESHAP applicability. There is no NSPS applicable to cooling towers. The cooling towers are currently subject to NESHAP, Subpart CC and that will not change as a result of this minor modification.

G. Analysis of Applicable Requirements under Subchapter 8

Significant Modification

A facility is required to obtain a permit for a significant modification if the change meets the criteria specified in OAC 252:100-8-7.2(b)(2)(A):

(i) Involve any significant changes in existing monitoring requirements in the permit;

This project does not change monitoring requirements.

(ii) Relax any reporting or recordkeeping requirements.

There will be no relaxation of recordkeeping requirements.

(iii) Change any permit condition that is required to be based on a case-by-case determination of an emission limitation or other standard, on a source-specific determination of ambient impacts, or on a visibility or increment analysis;

There changes to the permit conditions were not based on a case-by-case determination of an emission limit or other standard, on a source-specific determination of ambient impacts, or on a visibility increment analysis.

(iv) Seek to establish or change a permit term or condition for which there is no corresponding underlying applicable requirement or state-only requirement which the source has assumed to avoid some other applicable requirement or state-only requirement to which the source would otherwise be subject. Such terms and conditions include:

(I) A federally enforceable emissions cap assumed to avoid classification as a modification under any provision of Title I;

There is no need to establish or to change any permit condition or federally enforceable emission cap to authorize this project. Under the new configuration EUG 42B and EUG 42D will be subject to the same applicable requirements as they were before the project.

(II) An alternative emissions limit approved pursuant to regulations promulgated under section 112(i)(5) of the Act; and

The will be no establishment or change in any emissions limit.

(v) Are modifications under any provision of Title I of the Act; and,

New Source Performance Standards (NSPS):
Under section 111 of the Act, the term "modification" means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted. Explanation: neither cooling tower is or will become subject to any NSPS.

National Emission Standards for Hazardous Air Pollutants (NESHAP):
Under section 112 of the Act, the term "modification" means any physical change in, or change in the method of operation of, a major source which increases the actual emissions of any hazardous air pollutant emitted by such source by more than a de minimis amount or which results in the emission of any hazardous air pollutant not previously emitted by more than a de minimis amount. Rulemaking-to-date implements these requirements for construction and reconstruction only. Explanation: The cooling towers remain subject to the MACT requirements of NESHAP, Subpart CC.

Prevention of Significant Deterioration (PSD):
Major modification means:

Any physical change in or change in the method of operation of a major stationary source that would result in a significant emissions increase of a regulated NSR pollutant and a significant net emissions increase of that pollutant from the major stationary source is a major modification. Explanation: The project will not result in a significant emissions increase of a regulated NSR pollutant so it is not a major modification.

The requested changes are not modifications under any provision of Title I of the Act.

(vi) Do not qualify as minor permit modifications or administrative amendments.

The change is a minor modification.

Minor Modification

A minor modification is a revision to the permit that cannot be accomplished under an administrative amendment [OAC 252:100-8-7.2(a)] and is not a significant modification. The project will be a minor modification, incorporating changes to the specific conditions as requested.

Application for Applicability Determination No. 2012-1523-AD (M-10)

A. Description of the Project and Associated Process Changes

Valero requested an applicability determination to confirm that they could rebuild Tank T-1018 under the current permit without performing a minor modification to the Title V operating permit. The storage vessel that was the subject of this determination (T-1018) was used to store stabilized naphtha which is then fed into the hydrotreating unit storage tank. However, storage vessel contents may vary depending on refinery needs. The tank was an external floating roof (EFR) tank with a storage capacity of approximately 62,850 bbl. After the project, the tank was rebuilt (T-1018R) with the same capacity, but with upgraded internals.

The finding of the determination was that the physical change did not require a modification to the Title V operating permit. This determination was issued on August 11, 2020.

B. Equipment Associated with the Project

EUG 1 External Floating Roof (EFR)
Group 1 Storage Vessels Subject To NESHAP, Subpart CC

EU	Point	Roof Type	Contents	Barrels	Const. or Reconstr. Date
~~T-1018~~	~~F1~~	~~External Floating~~	~~Alkylate & Gasoline~~	~~62,850~~	~~1953~~
T-1018R	F1	External Floating	Alkylate & Gasoline	62,850	2018

C. Emissions Associated with the Project

Valero calculated emissions associated with the project and compare those emissions with those from the existing tank using EPA's TANKS 4.0.9d and the input parameters included in the following table.

Tank Parameters

Parameter	T-1018 (To Be Removed)	T-1018R (Replacment)
EUG	1	1
Tank Contents [1]	Gasoline	Gasoline
Product TVP (psi) [2]	11.1	11.1
Governing Rule Applicability	NESHAP CC	NESHAP CC
Tank Type	EFR	EFR
Roof Type	Pontoon	Pontoon
Diameter (ft)	90	90
Working Volume (gal.)	2,265,237	2,265,237
Throughput (gal./yr) [3]	398,580,000	398,580,000
Shell Color	White	White
Shell Paint Condition	Good	Good
Roof Color	White	White
Roof Paint Condition	Good	Good
Construction	Welded	Welded
Roof Fittings [4]	Provided in TANKS Output	Provided in TANKS Output
Primary Seal	Mechanical Shoe	Mechanical Shoe
Secondary Seal	Shoe-Mounted	Rim-Mounted
Withdrawal Loss (VOC TPY) [5]	0.42	0.42
Standing Loss (VOC TPY) [5]	20.66	8.56
MSS (VOC TPY) [6]	2.00	2.00
Total (VOC TPY)	**23.08**	**10.98**

1 The contents of the storage vessel will vary depending on refinery requirements, but will be limited by the suitability of the tank for a particular hydrocarbon. Gasoline represents a conservative (higher RVP) option.
2 This true vapor pressure (TVP) represents a worst-case scenario for this vessel. It is anticipated that the stored product will likely have a TVP of around 2.8 psi.
3 This throughput is not representative of a permit limit for this particular tank. The permit limits VOC emissions from all storage tanks in EUGs 1-8 to a maximum 12-month rolling total (185.6 tons). Compliance with this limit is demonstrated by calculating emissions using throughput and maximum true vapor pressure of the material stored in each vessel each month.
4 The roof fittings (numbers of fittings and types) were provided in the TANKS 4.0.9d emissions output. A summary is reproduced in a table below.
5 Withdrawal and standing losses were calculated using TANKS 4.0.9d.
6 Emissions associated with maintenance, startup, and shutdown were conservatively estimated using the entire value for tank degassing, changes in service, and maintenance included in EUG 41.

Tank Fittings – Summary of Differences

Description	Tank T-1018	Description	Tank T-1018R
Access hatch (24-in. diameter), bolted cover, gasketed	3	Access hatch (24-in. diameter), bolted cover, gasketed	2
Automatic gauge float well, bolted cover, gasketed	1	Gauge hatch/sample well (8-in. diameter), weighted, mechanical actuation, gasketed	1
Vacuum breaker (10-in. diameter), weighted mechanical actuation, gasketed	1	Vacuum breaker (10-in. diameter), weighted mechanical actuation, gasketed	2
Roof drain (3-in. diameter), 90% closed	1	Roof drain (3-in. diameter), 90% closed	1
Roof leg (3-in. diameter), adjustable, pontoon area, gasketed	16	Roof leg (3-in. diameter), adjustable, pontoon area, sock	14
Roof leg (3-in. diameter), adjustable, center area, gasketed	14	Roof leg (3-in. diameter), adjustable, center area, sock	13
Column well (24-in. diameter), pipe column-sliding cover, gasketed	1	Slotted guide-pole, sample well, gasketed sliding cover, with pole sleeve, wiper	1

D. PSD Evaluation

An evaluation was performed to determine whether the project constitutes a major modification as defined in OAC 252:100-8-30(b). To determine whether project emission increases constitute a "significant emissions increase," potential emissions from the rebuilt/replacement tank were used in the actual-to-potential test for projects that only involve construction of a new emission unit. It should be noted that the facility determined maximum throughput (and, by proxy, PTE) for the tank using professional judgement and an understanding of facility bottlenecking issues. There are no associated emissions increases for this project.

Project Emission Increases Calculations

	VOC
	TPY
Baseline Actual Emissions	**0.00**
Associated Emission Increases	**0.00**
AE-BAE[1]	**0.00**
Potential Emissions	**10.98**
PAE-(AE-BAE)-BAE[2]	**10.98**
Significance Levels	**40**
< Significance Level	**YES**

[1] Emissions that the facility could have accommodated during the baseline period that are unrelated to the project that can be excluded from the facility's PAE per OAC 252:100-8-31. As mentioned previously, Valero did not exclude emissions (due to demand growth) from their calculations.

[2] Project emission increases.

The project emission increases for this project were below the significance levels for the pollutants of concern. Because project emissions were below the significance level, evaluation of greenhouse gas (GHG) emission increases associated for this project was not required.

E. Evaluation of the Project for NSR Project Aggregation

Project aggregation issues were addressed for all of the projects discussed in this permitting action earlier in Section III. This project (M-10) raised no additional project aggregation issues that need to be addressed in greater depth.

F. Evaluation of the Project for NSPS and NESHAP Applicability

The existing tank was constructed in 1953 and it was not subject to NSPS as a new, modified, or reconstructed tank. However, the tank *was* subject to NESHAP, Subpart CC. A new, modified, or reconstructed tank will be subject to NSPS, Subpart Kb. Due to the overlapping requirements of NESHAP, Subpart CC, any Group 1 or Group 2 storage vessel at an existing source subject to the provisions of NSPS, Subpart Kb, and NESHAP, Subpart CC, is only required to comply with NSPS, Subpart Kb, except as provided in § 63.640(n)(8)(i) through (iv). Those paragraphs describe various deviations from the Kb requirements allowable for tanks subject to the MACT.

Because the existing tank is subject to NESHAP, Subpart CC, and the owner/operator has elected to comply with the requirements of Subpart CC, the rebuilt tank will remain subject to the same requirements as the existing tank.

It should be noted that, after the rebuild is completed, Tank T-1018 (which will be designated T-1018R) will be *formally* subject to NSPS, Subpart Kb, and the tank will be moved from EUG 1 to an new EUG for external floating roof tanks subject to NSPS, Subpart Kb, and NESHAP, Subpart CC. This change in the permit did not actually result in any changes to the applicable requirements and this change will be incorporated into the Title V operating permit under this permitting action.

G. Analysis of Applicable Requirements under Subchapter 8

The facility is an existing major source of criteria pollutants and HAPs that operates under a Title V (Part 70) operating permit governed by OAC 252:100-8 (Subchapter 8). Subchapter 8 establishes requirements for facilities to obtain construction permits and operating permit modifications to authorize changes to the facility.

Significant Modification

A facility is required to obtain a permit for a significant modification if the change meets the criteria specified in OAC 252:100-8-7.2(b)(2)(A):

(i) Involve any significant changes in existing monitoring requirements in the permit;

The rebuilt tank will be subject to the same monitoring requirements.

(ii) Relax any reporting or recordkeeping requirements.

There will be no relaxation of recordkeeping requirements.

(iii) Change any permit condition that is required to be based on a case-by-case determination of an emission limitation or other standard, on a source-specific determination of ambient impacts, or on a visibility or increment analysis;

There is no need to change any permit condition to authorize the rebuild.

(iv) Seek to establish or change a permit term or condition for which there is no corresponding underlying applicable requirement or state-only requirement which the source has assumed to avoid some other applicable requirement or state-only requirement to which the source would otherwise be subject. Such terms and conditions include:

(I) A federally enforceable emissions cap assumed to avoid classification as a modification under any provision of Title I;

There is no need to establish or to change any permit condition or federally enforceable emission cap to authorize the rebuild. The rebuilt tank will be subject to the same applicable requirements as the existing tank.

(II) An alternative emissions limit approved pursuant to regulations promulgated under section 112(i)(5) of the Act; and
The will be no establishment or change in any emissions limit.

(v) Are modifications under any provision of Title I of the Act; and,

New Source Performance Standards (NSPS):
Under section 111 of the Act, the term "modification" means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted. Explanation: the rebuilt tank will not result in an increase in emissions of any air pollutant or the emission of any air pollutant no previously emitted. It is not a modification under NSPS.

National Emission Standards for Hazardous Air Pollutants (NESHAP):
Under section 112 of the Act, the term "modification" means any physical change in, or change in the method of operation of, a major source which increases the actual emissions of any hazardous air pollutant emitted by such source by more than a de minimis amount or which results in the emission of any hazardous air pollutant not previously emitted by more than a de minimis amount. Rulemaking-to-date implements these requirements for construction and reconstruction only. Explanation: The rebuilt tank will not increase actual emissions of any HAP; the rebuilt tank will remain subject to the MACT requirements of NESHAP, Subpart CC.

Prevention of Significant Deterioration (PSD):
Major modification means:
Any physical change in or change in the method of operation of a major stationary source that would result in a significant emissions increase of a regulated NSR pollutant and a significant net emissions increase of that pollutant from the major stationary source is a major modification. Explanation: The rebuilt tank will not result in a significant emissions increase of a regulated NSR pollutant so it is not a major modification.

The requested changes are not modifications under any provision of Title I of the Act.

(vi) Do not qualify as minor permit modifications or administrative amendments.

The change is not a minor modification and it does not require an administrative amendment.

Minor Modification

A minor modification is a revision to the permit that cannot be accomplished under an administrative amendment [OAC 252:100-8-7.2(a)] and is not a significant modification. The rebuilt tank will continue to be subject to the same requirements as the existing tank. No modification to the permit is required.

<u>Operational Flexibility</u>

As specified in OAC 252:100-8-6(f)(1), "A facility may implement any operating scenario allowed for in its Part 70 permit without any need for any permit revision or any notification to the permitting authority." OAC 252:100-8-6(f)(2) establishes the following criteria for changes that a facility may make where the changes result in no emission increases:

(A) Such a source may make changes that are not modifications under any provision of Title I of the Act.

The changes are not modifications under any provision of Title I of the Act as discussed previously.

(B) Such a source may make changes that do not cause any hourly or annual permitted emission rate of any existing emissions unit to be exceeded.

The changes do not result in any emission increases or exceedances of any hourly or annual permitted emission rate.

(C) Such a source may make changes that result in a net change in emissions of zero, provided that the facility notifies the DEQ and EPA in writing at least 7 days in advance of the proposed changes. The source, DEQ, and EPA shall attach each such notice to their copy of the relevant permit. For each such change, the written notification required above shall include a brief description of the change within the permitted facility, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable as a result of the change. The permit shield described in OAC 252:100-8-6(d) does not apply to any change made pursuant to this subsection.

The permittee has notified the DEQ of the change

Application for Minor Modification No. 2012-1523-TVR (M-11)

A. Description of the Project and Associated Process Changes

Valero requested a minor modification to authorize the replacement of an existing process heater (H-407) with a new steam reboiler which uses steam from an existing 600 pound steam boiler (B-15001). The existing process heater that will be removed from service provides heat to the Platform Debutanizer column. The new steam reboiler will serve the same purpose. Process heater H-407 is a fired unit with a 25 MMBtu/hr capacity. The new steam reboiler will not be an emission unit, because it will use steam from an existing steam boiler (B-15001).

B. Equipment Associated with the Project

EUG 11 Combustion Units Subject to NSPS, Subpart J & OAC 252:100-19

EU	Point	Description	MMBTUH	Const. Date
~~H-407~~	~~P55~~	~~Process Heater~~	~~25.0~~	~~1974~~

EUG 13B Combustion Units
Subject to NSPS, Subpart Ja & OAC 252:100-19

EU	Point	Description	MMBTUH	Const. Date
B-15001	P240	Boiler	285.3	January 2015

C. Emissions Associated with the Project

The steam boiler (B-15001) was installed in July 2016, which falls within the 24-month period prior to Valero's submission of the application for the minor modification. In accordance with OAC 252:100-8-30(b)(3) through (6) and the definition of "baseline actual emissions" in OAC 252:100-8-31, Valero may calculate associated emissions increases from this unit (B-15001) using the actual-to-potential test where baseline actual emissions are equal to the unit's PTE. Using this analysis, Valero determined that associated emissions increases will be zero.

To confirm that there will be no associated emissions increases due to debottlenecking upstream or downstream of the debutanizer, AQD asked Valero a number of questions. Those questions and Valero's responses are provided below.

AQD Question: Why is Valero making this change?

Valero's Response: This change is being made to reduce the potential pressure safety valve relieving rate during loss of overhead cooling/reflux.

AQD Question: Has the existing fired heater experienced significant downtime?

Valero's Response: No

AQD Question: Will the new configuration yield an increase in utilization or uptime?

Valero's Response: No, this is only to reduce the potential relieving load to the flare during a safety event. The exchanger is sized to provide a similar heat input to the fired heater (H-407).

AQD Question: Will the new unit provide better process control?

Valero's Response: No.

AQD concurs with Valero that, since the 600 pound steam boiler (B-15001) has been operating less than 24 months, the unit's baseline actual emissions may be represented as the unit's PTE and, therefore, there would be no project emissions increases for this unit. AQD also concurs that the new reboiler will not be an emissions unit.

D. PSD Evaluation

After considering Valero's responses to the questions presented above, AQD agrees with Valero's contention that potential upstream and downstream impacts and potential associated emissions increases will be negligible and project emission increases are below PSD significant emission rates (SERs).

E. Evaluation of the Project for NSR Project Aggregation

The installation of the steam boiler (B-15001) was a necessary precondition for the installation of the steam reboiler to replace the fired process heater (H-407). However, the time that elapsed between the application for the construction permit for the steam boiler (April 2, 2014) and the application for the minor modification to remove the process heater from service, replacing it with a steam reboiler (January 30, 2018) places the projects outside the window that would necessitate additional scrutiny regarding project aggregation. This difference in time, along with the responses provided by Valero and discussed in the earlier portion of Section III, leads AQD to concur with Valero's claim that these are separate projects.

F. Evaluation of the Project for NSPS and NESHAP Applicability

The new steam reboiler is not an emission unit and is not subject to NSPS or NESHAP.

G. Analysis of Applicable Requirements under Subchapter 8

<u>Significant Modification</u>

A facility is required to obtain a permit for a significant modification if the change meets the criteria specified in OAC 252:100-8-7.2(b)(2)(A):

(i) Involve any significant changes in existing monitoring requirements in the permit;

This project will not change monitoring requirements.

(ii) Relax any reporting or recordkeeping requirements.

There will be no relaxation of recordkeeping requirements.

(iii) Change any permit condition that is required to be based on a case-by-case determination of an emission limitation or other standard, on a source-specific determination of ambient impacts, or on a visibility or increment analysis;

The requested changes do not require or change a case-by-case determination of an emission limitation or other standard, or a source-specific determination for temporary sources of ambient impacts, or a visibility or increment analysis. The emission increases from the new equipment are less than the PSD SERs so Best Available Control Technology (BACT) Analyses and modeling are not required.

(iv) Seek to establish or change a permit term or condition for which there is no corresponding underlying applicable requirement or state-only requirement which the source has assumed to avoid some other applicable requirement or state-only requirement to which the source would otherwise be subject. Such terms and conditions include:

(I) A federally enforceable emissions cap assumed to avoid classification as a modification under any provision of Title I;

This modification does not seek to establish or change a permit term of condition to avoid applicable requirements. The PTE of the new equipment is less than the PSD SERs so the facility is not taking a limit to avoid PSD.

(II) An alternative emissions limit approved pursuant to regulations promulgated under section 112(i)(5) of the Act; and

The project does not seek an alternative emissions limit under section 112(i)(5) of the Act.

(v) Are modifications under any provision of Title I of the Act; and,

<u>New Source Performance Standards (NSPS):</u>
Under section 111 of the Act, the term "modification" means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted. Explanation: The new steam reboiler will not be subject to NSPS.

<u>National Emission Standards for Hazardous Air Pollutants (NESHAP):</u>
Under section 112 of the Act, the term "modification" means any physical change in, or change in the method of operation of, a major source which increases the actual emissions of any hazardous air pollutant emitted by such source by more than a de minimis amount or which results in the emission of any hazardous air pollutant not previously emitted by more than a de minimis amount. Rulemaking-to-date implements these requirements for construction and reconstruction only. Explanation: The new steam reboiler will not be subject to NESHAP.

<u>Prevention of Significant Deterioration (PSD):</u>
Major modification means:
Any physical change in or change in the method of operation of a major stationary source that would result in a significant emissions increase of a regulated NSR pollutant and a significant net emissions increase of that pollutant from the major stationary source is a major modification. Explanation: The project will result in no emissions increases.

The requested changes are not modifications under any provision of Title I of the Act.
(vi) Do not qualify as minor permit modifications or administrative amendments.

The change will be authorized as a minor modification.

Minor Modification

A minor modification is a revision to the permit that cannot be accomplished under an administrative amendment [OAC 252:100-8-7.2(a)] and is not a significant modification. The project will be undertaken as a minor modification.

Application for Minor Modification No. 2012-1523-TVR (M-12)

A. Description of the Project and Associated Process Changes

Valero requested a minor modification to authorize the installation of a new emergency generator engine for a new administration building. The engine will be diesel-fired with a horsepower expected to be approximately 536 hp. The engine will be subject to NSPS, Subpart IIII, and NESHAP, Subpart ZZZZ.

B. Equipment Associated with the Project

EUG 20 Limited Use/Emergency Internal Combustion Engines Subject to NSPS, Subpart IIII or JJJJ and/or NESHAP, Subpart ZZZZ

EU	Point	Make/Model	HP	Serial #	Const. Date
EG-ADMIN	P91	Cummins Model QSX15-G9	536	40013112	2018

C. Emissions Associated with the Project

Valero estimated emissions associated with the new emergency engine based on the following engine specifications.

Engine Data Summary

Parameter	Data
Engine Make	Cummins
Engine Model	Model QSX15-G9
Fuel	Diesel
Emissions Classification	Tier 3
NSPS Applicability	Subpart IIII
NESHAP Applicability	Subpart ZZZZ
Post-Combustion Control Device	None
Maximum Horsepower	536
Brake-Specific Fuel Combustion (Btu/hp•hr)	7,205
Operating Hours per Year	500
Emission Factors (below) [1]	
NOx (g/hp•hr)	2.98
CO (g/hp•hr)	2.61
VOC (g/hp•hr)	1.14

Engine Data Summary

Parameter	Data
Formaldehyde (g/hp•hr)	0.00386
SO_2 (g/hp•hr)	0.00507
PM-10/2.5 (g/hp•hr)	0.150
Total HAP (g/hp•hr)	0.0124
CO_2 (g/hp•hr)	533
CH_4 (g/hp•hr)	0.0216
N_2O (g/hp•hr)	0.00432

[1] Emission factors are based on Tier 3 limits where applicable or AP-42, Chapter 3.3. The SO_2 factor is based on a mass balance assuming 15 ppmw sulfur in the fuel (ultra low sulfur diesel). VOC (as non-methane hydrocarbons) and NOx have a combined limit of 2.98 g/hp•hr.

Emissions Summary

	Emissions	
Pollutant	**lb/hr**	**TPY**
NOx	3.52	0.88
CO	3.09	0.77
VOC	1.35	0.34
Formaldehyde	<0.01	<0.01
SO_2	<0.01	<0.01
PM-10/2.5	0.18	0.04
Total HAP	0.01	<0.01
CO_2	630.12	157.53
CH_4	0.03	<0.01
N_2O	<0.01	<0.01
CO_2e	632.29	158.07

D. PSD Evaluation

The installation of the new engine will not result in a significant emissions increase of a regulated NSR pollutant.

E. Evaluation of the Project for NSR Project Aggregation

Project aggregation issues were addressed for ***all*** of the projects discussed in this permitting action earlier in Section III. This project (M-12) raised no additional project aggregation issues that need to be addressed in greater depth.

F. Evaluation of the Project for NSPS and NESHAP Applicability

The engine will be subject to NSPS, Subpart IIII, and NESHAP, Subpart ZZZZ.

G. Analysis of Applicable Requirements under Subchapter 8

<u>Significant Modification</u>

A facility is required to obtain a permit for a significant modification if the change meets the criteria specified in OAC 252:100-8-7.2(b)(2)(A):

(i) Involve any significant changes in existing monitoring requirements in the permit;

This project will not change monitoring requirements.

(ii) Relax any reporting or recordkeeping requirements.

There will be no relaxation of recordkeeping requirements.

(iii) Change any permit condition that is required to be based on a case-by-case determination of an emission limitation or other standard, on a source-specific determination of ambient impacts, or on a visibility or increment analysis;

The requested changes do not require or change a case-by-case determination of an emission limitation or other standard, or a source-specific determination for temporary sources of ambient impacts, or a visibility or increment analysis. The emission increases from the new equipment are less than the PSD SERs so BACT Analyses and modeling are not required.

(iv) Seek to establish or change a permit term or condition for which there is no corresponding underlying applicable requirement or state-only requirement which the source has assumed to avoid some other applicable requirement or state-only requirement to which the source would otherwise be subject. Such terms and conditions include:

(I) A federally enforceable emissions cap assumed to avoid classification as a modification under any provision of Title I;

This modification does not seek to establish or change a permit term of condition to avoid applicable requirements. The PTE of the new equipment is less than the PSD SERs so the facility is not taking a limit to avoid PSD.

(II) An alternative emissions limit approved pursuant to regulations promulgated under section 112(i)(5) of the Act; and

The project does not seek an alternative emissions limit under section 112(i)(5) of the Act.

(v) Are modifications under any provision of Title I of the Act; and,

<u>New Source Performance Standards (NSPS):</u>
Under section 111 of the Act, the term “modification” means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any

air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted. Explanation: The installation of the new engine is considered new construction and not a modification under NSPS.

National Emission Standards for Hazardous Air Pollutants (NESHAP):
Under section 112 of the Act, the term "modification" means any physical change in, or change in the method of operation of, a major source which increases the actual emissions of any hazardous air pollutant emitted by such source by more than a de minimis amount or which results in the emission of any hazardous air pollutant not previously emitted by more than a de minimis amount. Rulemaking-to-date implements these requirements for construction and reconstruction only. Explanation: The new engine is subject to NESHAP, Subpart ZZZZ, but modification is not defined in NESHAP, Subpart ZZZZ.

Prevention of Significant Deterioration (PSD):
Major modification means:
Any physical change in or change in the method of operation of a major stationary source that would result in a significant emissions increase of a regulated NSR pollutant and a significant net emissions increase of that pollutant from the major stationary source is a major modification. Explanation: The installation of the new engine does not result in a significant emissions increase of a regulated NSR pollutant so it is not a major modification.

The requested changes are not modifications under any provision of Title I of the Act.

(vi) Do not qualify as minor permit modifications or administrative amendments.

The change will be authorized as a minor modification.

Minor Modification

A minor modification is a revision to the permit that cannot be accomplished under an administrative amendment [OAC 252:100-8-7.2(a)] and is not a significant modification. The project will be undertaken as a minor modification.

Application for Minor Modification No. 2012-1523-TVR (M-13)

A. Description of the Project and Associated Process Changes

Valero requested a minor modification to authorize installation of replacement feed filters and a new filter tray in the catalytic feed hydrotreater (CFHT) reactor R-6502 (R-2). The filters will improve the quality of feed provided to the CFHT Guard Bed reactor, reducing fouling and allowing for an increase in the quantity of Vacuum Tower Bottoms (VTB) residual oil that may be processed by the unit between required catalyst change-outs. It should be noted that when the CFHT hydrotreater is taken out of service, untreated feed is able to bypass the unit, so this project will not increase the facility’s overall throughput.

The project involves the installation of a filter tray to the R-2 reactor and a change in the existing feed filter to a Filtrex model filter unit. Additional piping components will be installed in EUG 31, EU LDAR 650 and these will constitute the only new sources of emissions.

B. Equipment Associated with the Project

There are no new emission units associated with this project, except for piping and related components that constitute fugitive sources which are included in existing EUG 31, EU LDAR 650.

EUG 31 Fugitive Equipment Leaks Subject to LDAR Programs
NSPS, Subpart GGG & NESHAP, Subpart CC

EU	Point	Description
LDAR 650	F34	Area 650 – CFHT Unit

C. Emissions Associated with the Project

Project emissions increases include fugitive releases from the new components and associated emissions increases from existing components.

New Fugitive Component VOC Emissions from EUG 31, EU LDAR 650

Number Items	Type of Equipment	Factor (lb/hr/source)	Emissions (TPY)
60	Heavy-Liquid Valves	4.87×10^{-3}	1.28
150	Heavy-Liquid Flanges	6.59×10^{-3}	4.33
Total			**5.61**

Fugitive VOC emissions are based on the factors above derived from EPA's *1995 Protocol for Equipment Leak Emission Estimates* (EPA-453/R-95-017), a $\%C_{3+}$ of 100%, and an estimated number of components. The fugitive emission factors were derived from the screening values established under NSPS, Subpart VV.

In addition to estimating emissions from the new fugitive sources, Valero evaluated associated emissions increases from units upstream and downstream of this change. Only two existing units will experience project emissions increases: the two process heaters in the CFHT unit, H-6501 and H-6502 (EUG 10 and EUG9, respectively). Associated emissions increases from these existing units were calculated using the actual-to-projected-actual applicability test, OAC 252:100-8-30(b)(3).

Production Parameter Comparison for
Baseline and Projected Actual Emissions Calculations

EU	Unit Description	Baseline [1] Production Rate (MM Btu/hr)	Projected Future Production Rate [2] (MM Btu/hr)	Production Parameter Description
H-6501	Process Heater	46.71	99.70	Firing Rate
H-6502	Process Heater	40.01	54.30	Firing Rate

1 The baseline production rate is the annual average production rate during the baseline period: June 2015 to May 2017.

2 The projected future production rate is based on process knowledge of the downstream impacts of the project changes.

Emissions for H-6501 and H-6502 were calculated using the heat input ratings (MMBtu/hr) on a higher heating value (HHV) basis and pollutant-specific emission factors.

Emission Factors for Units H-6501 and H-6502

Pollutant	EU	Emission Factor	Notes
NO_X	H-6501	0.0400 lb/MM Btu	Manufacturer's data.
NO_X	H-6502	0.06 lb/MM Btu	Manufacturer's data.
CO	Both	0.0404 lb/MM Btu	Manufacturer's data.
$PM_{2.5}$	Both	7.6 lb/MMscf	AP-42 (7/98), Section 1.4
SO_2	Both	0.0336 lb/MM Btu	A fuel-gas H_2S concentration of 0.1 grain/dry scf and a HHV of 800 Btu/scf
VOC	Both	5.5 lb/MMscf	AP-42 (7/98), Section 1.4

The baseline actual and projected actual emissions are presented in the following table.

Associated Emission Increases for Units H-6501 and H-6502

				NO_X	CO	$PM_{2.5}$	SO_2	VOC
EU	**EUG**	**Point**	**Category**	**TPY**	**TPY**	**TPY**	**TPY**	**TPY**
H-6501	10	P47	Baseline (BAE)	8.20	8.28	1.53	0.96	1.11
H-6501	10	P47	Projected (PAE)	17.51	17.68	3.26	2.06	2.36
H-6501			PAE-BAE	9.31	9.40	1.73	1.10	1.25
H-6502	9	P45	Baseline (BAE)	5.77	0.45	1.31	0.73	0.95
H-6502	9	P45	Projected (PAE)	7.83	0.61	1.77	0.99	1.28
H-6502			PAE-BAE	2.06	0.16	0.46	0.26	0.33
Existing Units – Project Emission Increases				**11.37**	**9.56**	**2.20**	**1.36**	**1.58**

D. PSD Evaluation

The facility is an existing major stationary source as defined in OAC 252:100-8-31. An evaluation was performed to determine whether the project constitutes a major modification as defined in OAC 252:100-8-30(b).

Project Emission Increases

Emission Units	NO_X	CO	$PM_{2.5}$	SO_2	VOC	CO_{2e}
	TPY	TPY	TPY	TPY	TPY	TPY
Potential to Emit for New Units [1]	0.00	0.00	0.00	0.00	5.61	--- [4]
Associated Emissions Increases for Existing Units [2]	11.37	9.56	2.20	1.36	1.58	---
Project Emission Increases [3]	11.37	9.56	2.20	1.36	7.20	---
Significance Levels	40	100	15	40	40	75,000

1 These are the fugitive emissions from new process piping components.
2 Unit-specific associated emissions increases are presented in the previous table.
3 The sum of individual pollutant project emission increases do not necessarily total exactly due to rounding.
4 For this permitting action, the associated emissions increases for CO_2e are not relevant to the analysis.

The project emissions increases for the CFHT feed filter replacement project were below the significance levels for all regulated pollutants. Because the project will result in no significant emissions increase for any other pollutant, the evaluation of greenhouse gas emission increases was not required. Associated emissions increases were based on the PAE to BAE test; therefore, the permittee is required to keep records of project emissions increases in accordance with OAC 252:100-36.2(c).

E. Evaluation of the Project for NSR Project Aggregation

Project aggregation issues were addressed for all of the projects discussed in this permitting action earlier in Section III. This project (M-13) raised no additional project aggregation issues that need to be addressed in greater depth.

F. Evaluation of the Project for NSPS and NESHAP Applicability

The only new emission sources are fugitive components. These components will be incorporated into an area with existing components which are currently subject to NSPS, Subpart GGG and NESHAP, Subpart CC. All of those components will continue to be subject to those requirements after the conclusion of the project.

G. Analysis of Applicable Requirements under Subchapter 8

Significant Modification

A facility is required to obtain a permit for a significant modification if the change meets the criteria specified in OAC 252:100-8-7.2(b)(2)(A):

(i) Involve any significant changes in existing monitoring requirements in the permit;

The project will not result in any changes in existing monitoring requirements.

(ii) Relax any reporting or recordkeeping requirements.

There will be no relaxation of recordkeeping requirements.

(iii) Change any permit condition that is required to be based on a case-by-case determination of an emission limitation or other standard, on a source-specific determination of ambient impacts, or on a visibility or increment analysis;

The project will not require the modification of any specific conditions.

(iv) Seek to establish or change a permit term or condition for which there is no corresponding underlying applicable requirement or state-only requirement which the source has assumed to avoid some other applicable requirement or state-only requirement to which the source would otherwise be subject. Such terms and conditions include:

(I) A federally enforceable emissions cap assumed to avoid classification as a modification under any provision of Title I;

There are no changes in federally enforceable emissions caps.

(II) An alternative emissions limit approved pursuant to regulations promulgated under section 112(i)(5) of the Act; and

The will be no establishment or change in any emissions limit.

(v) Are modifications under any provision of Title I of the Act; and,

New Source Performance Standards (NSPS):
Under section 111 of the Act, the term “modification” means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted. Fugitive components are currently subject to NSPS, Subpart GGG and those components will continue to be subject to those requirements after the conclusion of the project.

National Emission Standards for Hazardous Air Pollutants (NESHAP):
Under section 112 of the Act, the term "modification" means any physical change in, or change in the method of operation of, a major source which increases the actual emissions of any hazardous air pollutant emitted by such source by more than a de minimis amount or which results in the emission of any hazardous air pollutant not previously emitted by more than a de minimis amount. Fugitive sources will continue to be subject to NESHAP, Subpart CC. The project is not a modification under section 112 of the Act.

Prevention of Significant Deterioration (PSD):
Major modification means:
Any physical change in or change in the method of operation of a major stationary source that would result in a significant emissions increase of a regulated NSR pollutant and a significant net emissions increase of that pollutant from the major stationary source is a major modification. Project emissions increases are less than the PSD SERs so the project does not constitute a modification under PSD.

The requested changes are not modifications under any provision of Title I of the Act.

(vi) Do not qualify as minor permit modifications or administrative amendments.

The project is a minor modification.

Minor Modification

A minor modification is a revision to the permit that cannot be accomplished under an administrative amendment [OAC 252:100-8-7.2(a)] and is not a significant modification. The project cannot be accomplished under an administrative amendment. It is a minor modification.

Application for Minor Modification No. 2012-1523-TVR (M-14)

A. Description of the Project and Associated Process Changes

Valero requested a minor modification to authorize an increase in the flow rate of supplementary fuel gas (also referred to as “sweep gas”) to the Alky Flare, which is designated as EU HI-81002, in EUG 14. The facility is subject to NESHAP, Subpart CC, also known as “Refinery MACT 1” (Maximum Achievable Control Technology) or “MACT CC.” This project addresses updated requirements for flare control devices under 40 CFR §63.670. In particular, §63.670(e) requires that the net heating value of flare combustion zone gas (NHV_{cz}) be maintained at or above 270 British thermal units per square foot (Btu/scf), determined on a 15-minute block period basis when regulated material is routed to the flare for at least 15 minutes. To meet this requirement, Valero must increase the flow of supplemental fuel to the Alky Flare. In addition to this change, Valero requested an increase in the frequency of flare operation to accommodate an increase in the frequency of preventative maintenance activities performed on equipment in the associated Alkylation Unit. Aggregating these changes, Valero estimated that the maximum flow of supplemental fuel gas will increase from 10.93 million Btu per hour (MMBtu/hr) to 37.08 MMBtu/hr. Valero requested that the emission limits for the flare (based on heat input and standard emission factors) be increased to accommodate the required increase in fuel Btu content and the increased frequency of preventative maintenance. The flare is the only unit that will experience emission increases; there are no new sources of emissions.

This permitting action only addresses this issue. This project will not increase the facility’s overall throughput.

B. Equipment Associated with the Project

There are no new emission units associated with this project.

C. Emissions Associated with the Project

Valero calculated emissions increases from the flare using the actual-to-projected-actual applicability test 252:100-8-30(b)(3). The limits in the current permit were based on an estimate of the maximum flow of supplemental fuel required for the Alky flare: 10.93 MMBtu/hr. To comply with the new MACT CC requirements, this rate was increased to 37.08 MMBtu/hr. At an assumed average fuel gas higher heating value (HHV) of 800 Btu/scf, this corresponds to an increase in flare gas flow rate from 13,662.5 scf/hr to 46,355 scf/hr. This increase in flare gas flow will be entirely attributable to the increase in supplemental fuel gas supplied to the flare tip to maintain the higher heating value of the flare gas and the additional flaring associated with preventive maintenance. There will be no increase in the flow of process vapors routed to the Alky Flare. There are no additional upstream or downstream impacts associated with this change.

Emissions for HI-81002 were calculated using the heat input ratings (MMBtu/hr) on an HHV basis, the fuel heating value (Btu/scf), and pollutant-specific emission factors.

Emission Factors for Unit HI-81002, EUG 14

Pollutant	Emission Factor	Notes
NO_X	0.068 lb/MMBtu	AP-42 (1/95), Section 13.5
CO	0.37 lb/MMBtu	AP-42 (1/95), Section 13.5
$PM_{2.5}$	7.6 lb/MMscf	AP-42 (7/98), Section 1.4
SO_2	0.0336 lb/MMBtu	A fuel-gas H_2S concentration of 0.1 grain/dry scf and a HHV of 800 Btu/scf (projected actual emissions and the new permit limit) or the actual measured heating value for the baseline period, 1,325 Btu/scf (baseline actual emissions)
VOC	0.14 lb/MMBtu	AP-42 (1/95), Section 13.5

Baseline emissions are based on the 24-month baseline period from March 2015 through February 2017. Baseline actual emissions were calculated using the actual average total flare gas flow rate for the baseline period (6,133 scf/hr), the actual average fuel gas HHV (1,325 scf/hr), the fuel gas maximum allowable H_2S concentration (0.1 grain/dry scf), and the average Alky Flare header molecular weight (24.430 lb/lb-mol).

Projected actual emissions were calculated using the projected annual average firing rate (37.08 MMBtu/hr) and an estimate average fuel gas HHV (800 Btu/scf).

The baseline actual and projected actual emissions are presented in the following table.

Associated Emission Increases for Unit HI-81002, EUG 14

				NO_X	CO	$PM_{2.5}$	SO_2	VOC
EU	**EUG**	**Point**	**Category**	**TPY**	**TPY**	**TPY**	**TPY**	**TPY**
HI-81002	14	P64	Baseline (BAE)	1.76	9.75	0.27	0.90	3.70
HI-81002	14	P64	Projected (PAE)	11.04	60.09	1.54	5.46	22.74
HI-81002			PAE-BAE	9.28	50.34	1.27	4.56	19.04
Existing Units – Project Emission Increases				**9.28**	**50.34**	**1.27**	**4.56**	**19.04**

D. PSD Evaluation

The facility is an existing major stationary source as defined in OAC 252:100-8-31. An evaluation was performed to determine whether the project constitutes a major modification as defined in OAC 252:100-8-30(b).

Project Emission Increases

Emission Units	NO_X	**CO**	$PM_{2.5}$	SO_2	**VOC**	CO_{2e}
	TPY	**TPY**	**TPY**	**TPY**	**TPY**	**TPY**
Potential to Emit for New Units [1]	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**---** [4]
Associated Emissions Increases for Existing Units [2]	**9.28**	**50.34**	**1.27**	**4.56**	**19.04**	**---**
Project Emission Increases [3]	**9.28**	**50.34**	**1.27**	**4.56**	**19.04**	**---**
Significance Levels	**40**	**100**	**15**	**40**	**40**	**75,000**

1 There are no new units associated with this modification.
2 Unit-specific associated emissions increases are presented in the previous table.
3 The sum of individual pollutant project emission increases do not necessarily total exactly due to rounding.
4 For this permitting action, the associated emissions increases for CO_2e are not relevant to the analysis.

The project emissions increases for the project were below the significance levels for all regulated pollutants. Because the project will result in no significant emissions increase for any other pollutant, the evaluation of greenhouse gas emission increases was not required. Associated emissions increases were based on the PAE to BAE test; therefore, the permittee is required to keep records of project emissions increases in accordance with OAC 252:100-36.2(c).

E. Evaluation of the Project for NSR Project Aggregation

Project aggregation issues were addressed for all of the projects discussed in this permitting action earlier in Section III. This project (M-14) raised no additional project aggregation issues that need to be addressed in greater depth.

F. Evaluation of the Project for NSPS and NESHAP Applicability

There were no new emission sources installed in association with this project. The flare will increase emissions to comply with NESHAP, Subpart CC and to accommodate additional flaring for preventative maintenance. This is not considered to be a modification under NSPS or NESHAP.

G. Analysis of Applicable Requirements under Subchapter 8

Significant Modification

A facility is required to obtain a permit for a significant modification if the change meets the criteria specified in OAC 252:100-8-7.2(b)(2)(A):

(i) Involve any significant changes in existing monitoring requirements in the permit;

The project will not result in any changes in existing monitoring requirements.

(ii) Relax any reporting or recordkeeping requirements.

There will be no relaxation of recordkeeping requirements.

(iii) Change any permit condition that is required to be based on a case-by-case determination of an emission limitation or other standard, on a source-specific determination of ambient impacts, or on a visibility or increment analysis;

The project will result in a change in the emission limits for the flare (Specific Condition 2, EUG 14). This permit condition change does not change a limit that was based on a case-by-case determination of an emission limitation or other standard, on a source-specific determination of ambient impacts, or on a visibility or increment analysis. The project emissions increases are less than the PSD SERs so the facility is not taking a limit to avoid PSD or any other requirement.

(iv) Seek to establish or change a permit term or condition for which there is no corresponding underlying applicable requirement or state-only requirement which the source has assumed to avoid some other applicable requirement or state-only requirement to which the source would otherwise be subject. Such terms and conditions include:

(I) A federally enforceable emissions cap assumed to avoid classification as a modification under any provision of Title I;

There are no changes in federally enforceable emissions caps that were assumed to avoid classification as a modification under any provision of Title I.

(II) An alternative emissions limit approved pursuant to regulations promulgated under section 112(i)(5) of the Act; and

The change in emissions limit is not associated with an alternative emission limit approved pursuant to section 112(i)(5) of the Act.

(v) Are modifications under any provision of Title I of the Act; and,

New Source Performance Standards (NSPS):
Under section 111 of the Act, the term "modification" means any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted. The Alky flare is a control unit, subject to NSPS, Subpart Ja. The increase in emissions is not due to a physical change or change in the method of operations.

National Emission Standards for Hazardous Air Pollutants (NESHAP):
Under section 112 of the Act, the term "modification" means any physical change in, or change in the method of operation of, a major source which increases the actual emissions of any hazardous air pollutant emitted by such source by more than a de minimis amount or which results in the emission of any hazardous air pollutant not previously emitted by more than a de minimis amount. The flare will continue to be subject to NESHAP, Subpart CC. The project is not a modification under section 112 of the Act.

Prevention of Significant Deterioration (PSD):
Major modification means:
Any physical change in or change in the method of operation of a major stationary source that would result in a significant emissions increase of a regulated NSR pollutant and a significant net emissions increase of that pollutant from the major stationary source is a major modification. Project emissions increases are less than the PSD SERs so the project does not constitute a modification under PSD.

The requested changes are not modifications under any provision of Title I of the Act.

(vi) Do not qualify as minor permit modifications or administrative amendments.

The project is a minor modification, therefore it is not a significant modification.

Minor Modification

A minor modification is a revision to the permit that cannot be accomplished under an administrative amendment [OAC 252:100-8-7.2(a)] and is not a significant modification. The project cannot be accomplished under an administrative amendment. It is a minor modification.

Application for Renewal of the Title V Operating Permit

Permit No. 2019-0630-TVR2

There is no project to analyze; however, Valero requested administrative changes to the Title V operating permit. These changes are in addition to those mentioned in the description of the earlier permitting actions.

Elimination of three tanks whose construction was authorized in 2006 as part of the Ultra-Low Sulfur Diesel (ULSD) project, but were never actually constructed. The tanks to removed are identified below.

EUG 2B Cone Roof (CR)
Group 2 Storage Vessels Subject To NSPS, Subpart Kb
[Tanks to Be Removed – Never Constructed]

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-100161	P15	Cone	Biodiesel – 100%	1,500	Never Built
T-100162	P16	Cone	Biodiesel – 100%	1,500	Never Built
T-100163	P17	Cone	Biodiesel – 5%, Diesel – 95%	1,500	Never Built

In addition, Valero moved an existing, permitted emergency generator (EG 1880-02), which was located at the old administration building, to another location: the Central Control Room. The emergency generator located at the Central Control Room (EEQ-80001) was taken out of service.

EUG 20 Limited Use/Emergency Internal Combustion Engines
Subject to NSPS, Subpart IIII or JJJJ and/or NESHAP, Subpart ZZZZ
[Changes: Engine Moved and Another Taken Out of Service]

EU	Point	Make/Model	KW (HP)	Serial #	Const. Date	Status Change
EEQ-80001	P74	Cummins/6BT5.9G-2	80 (107)	45555233	1997	Taken Out of Service
EG1880-02	P80	Cummins QSTB-G5	100 (134)	???	2012	Moved to the Central Control Room

And, finally, Valero requested that references to the toluene rail car unloading station be removed, because Valero never unloaded toluene and does not expect to do so in the future. If plans change, Valero will request a permit modification.

EUG 28 Ethanol Unloading Station

EU	Point	Description	Const. Date
TolRC	F20	Toluene Rail Car Unloading Station	----

SECTION IV. EQUIPMENT - EMISSION UNIT (EU) GROUPS

STORAGE VESSELS

Storage vessel contents will vary depending upon refinery requirements, but will be limited by the suitability of a particular tank for a particular hydrocarbon.

EUG 1A External Floating Roof (EFR)
Group 1 Storage Vessels Subject To NESHAP, Subpart CC

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1019	F2	External Floating	Alkylate & Gasoline	66,868	1948
T-1082	F3	External Floating	Crude Oil	124,714	1974
T-1083	F4	External Floating	Crude Oil	124,714	1974
T-1084	F5	External Floating	Crude Oil	124,714	1978
T-1115	F6	External Floating	Gasoline W/Ethanol	27,205	1953
T-1116	F7	External Floating	Gasoline W/Ethanol	27,315	1953
T-1123	F8	External Floating	Gasoline /Diesel	60,766	1968
T-1124	F9	External Floating	Gasoline	111,721	1972
T-1125	F10	External Floating	Gasoline	124,398	1974
T-1126	F11	External Floating	Gasoline	124,412	1974
T-1130	F12	External Floating	Gasoline	79,414	9/1978
T-1131	F13	External Floating	Gasoline/FCCUGasoline/ ISOM/Hydrocracker Naptha	125,100	1979
T-1132	F14	External Floating	Reformate	80,138	1979

EUG 1B External Floating Roof (EFR)
Group 1 Storage Vessels Subject To NSPS, Subpart Kb and NESHAP, Subpart CC

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1018R	F1	External Floating	Alkylate & Gasoline	62,850	2018

EUG 2A Cone Roof (CR)
Group 2 Storage Vessels Subject To NESHAP, Subpart CC

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1127	P4	Cone	Diesel / Jet Fuel	80,579	1974
T-1129	P6	Cone	Diesel / Jet Fuel	2,113	1975
TK-13006	P13	Cone	Fuel Additives	485	1993

EUG 2B Cone Roof (CR)
Group 2 Storage Vessels Subject To NSPS, Subpart Kb

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1121	P3	Cone	Diesel /Jet Fuel /Distillate	40,526	2012
T-1128	P5	Cone	Diesel / Jet Fuel	80,574	2011
T-1141	P8	Cone	Diesel / Kerosene	119,189	1992
T-1142	P9	Cone	Diesel / Kerosene	79,445	1992
T-1153	P10	Cone	FCCU Charge/Asphalt	200,676	2003
T-1156	P11	Cone	FCCU Slurry/Fuel Oil No. 6/ Asphalt	56,000	2003
T-5801	P12	Cone	Amine	895	2003
TK-90002	P14	Cone	Acid Soluble Oil (ASO)	630	2008

EUG 3 EFR & Internal Floating Roof (IFR)
Group 1 & 2 Storage Vessel Subject To NSPS, Subpart Kb

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-1155	F15	External Floating	Heavy Naphtha/Distillate	163,555	2003
T-1152	F16	External Floating	Sour Water Stripper Feed	11,890	1999
T-100160	P18	Internal Floating	Ethanol	14,000	2010

EUG 5 CR, Group 2 Storage Vessels Subject To NESHAP, Subpart LLLLL

EU	Tank	Point	Roof Type	Contents	Barrels	Const. Date
T-1102	T-1102	P19	Cone	Asphalt /Gas Oil	75,786	1975
T-1113	T-1113	P21	Cone	Gas Oil / Asphalt	131,005	1959
T-1118	T-1118	P22	Cone	Asphalt	79,742	2012
T-1151	T-1151	P23	Cone	Asphalt	206,979	1998
T-100149	T-100149	P24	Cone	Asphalt Flux	35,847	1996
T-100150	T-100150	P25	Cone	Asphalt Base	35,847	1996
P-26 (includes the group of tanks indicated, which are configured to allow liquids to flow freely between the tanks and which have vent lines from each tank tied into a common manifold that routes vapors to the V-210001 PMA Vent Gas Scrubber, P-26)	T-210003	P186	Cone	Asphalt Flux	3,021	1996
	T-210004		Cone	Asphalt Rxn	6,526	1996
	T-210005		Cone	Asphalt Rxn	6,526	1996
	T-210006		Cone	Polymer Modified Asphalt	10,197	1996
	T-210007		Cone	Polymer Modified Asphalt	10,197	1996
	T-210008		Cone	Polymer Modified Asphalt	11,715	2001

EUG 6 EFR, Oil-Water Separators
Subject to NESHAP, Subpart CC & OAC 252:100-37

EU	Point	Roof Type	Contents	Barrels	Const. Date
V-8801	F17	External Floating	Oil / Water	17,200	1993
V-8802	F18	External Floating	Oil / Water	17,200	1993

EUG 7 CR, Storage Vessel Subject to NSPS, Subpart Kb & Subpart QQQ

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-83001	P32	Cone	Sour Water	18,885	1993

EUG 8 CR, Storage Vessel Subject to OAC 252:100-31

EU	Point	Roof Type	Contents	Barrels	Const. Date
T-5602	P33	Cone	Sulfur	3,644	2004

COMBUSTION UNITS

EUG 9 Combustion Units
Subject to NSPS, Subpart J & OAC 252:100-19 & 33

EU	Point	Description	MMBTUH	Const. Date
B-801	P34	Boiler	72.5	1974
B-802	P35	Boiler	89.8	1975
B-803	P36	Boiler	86.8	1979
H-102A	P37	Process Heater	160.0	Mod. 1998
H-102B	P38	Process Heater	135.0	Mod. 1998
H-103	P39	Process Heater	102.6	1974
H-201	P40	Process Heater	116.7	1974
H-403	P41	Process Heater	98.7	1980
H-404/5	P42	Process Heater	99.3	Mod. 1980
H-601	P43	Process Heater	58.5	1975
H-603	P44	Process Heater	125.5	1992
H-6502	P45	Process Heater	54.3	1992
H-15001	P46	Process Heater	326.8	1992

EUG 10 Combustion Units
Subject to NSPS, Subpart Ja & OAC 252:100-19 & 33

EU	Point	Description	MMBTUH	Const. Date
H-6501	P47	Process Heater	99.7	Mod. 2008

EUG 11 Combustion Units Subject to NSPS, Subpart J & OAC 252:100-19

EU	Point	Description	MMBTUH	Const. Date
H-101	P48	Process Heater	30.8	Mod. 1998
H-301	P49	Process Heater	21.6	1974
H-401A	P50	Process Heater	16.0	1969
H-401B	P51	Process Heater	14.8	1974
H-402A	P52	Process Heater	13.9	1970
H-402B	P53	Process Heater	15.8	1963
H-406	P54	Process Heater	28.0	1974
H-411	P56	Process Heater	28.0	1986
H-901	P57	Process Heater	60.0	1969
H-1016	P58	Process Heater	4.8	1954
H-6701	P62	Co-Processor Heater	11.8	2006

EUG 12 Combustion Units Subject to NSPS, Subparts J & Dc & OAC 252:100-19

EU	Point	Description	MMBTUH	Const. Date
H-100024	P59	Asphalt Tank Heater	13.5	1999
H-210001	P60	Process Heater	12.2	1996
H-5602	P61	Hot Oil Heater	20.0	2004

EUG 13 Combustion Units
Subject to NSPS, Subpart Ja & OAC 252:100-19

EU	Point	Description	MMBTUH	Const. Date
H-2601	P230	HDS Reactor Heater	13.2	4th Quarter 2014

EUG 13B Combustion Units
Subject to NSPS, Subpart Ja & OAC 252:100-19

EU	Point	Description	MMBTUH	Const. Date
B-15001	P240	Boiler	285.3	January 2015

OTHER EMISSION UNITS

EUG 14 Flares Subject to NSPS, Subparts A & J or Ja & NESHAP, Subpart A

EU	Point	Description	Mod. Date
HI-81001	P63	West Flare – 42” SASFF	2009
HI-81002	P64	HF Process Gas Flare – 20” SASFF	2010
HI-81003	P65	East Flare – 24” SASFF	2009

SASFF – Steam Assisted Smokeless Field Flare

EUG 15 SRU Incinerators
Subject to NSPS, Subpart J, NESHAP, Subpart UUU, & OAC 252:100-31

EU	Point	Description	Const. Date
HI-501	P66	#1 SRU Incinerator	1995
HI-5602	P67	#2 SRU Incinerator	2004

EUG 16 Asphalt Blowstill Incinerator
Subject to NSPS, Subparts A & J & NESHAP, Subparts A, CC, & LLLLL

EU	Point	Description	Const. Date
HI-801	P68	Asphalt Blowstill Incinerator	1992

EUG 17 Gasoline Loading Rack Vapor Combustor
Subject to NSPS, Subpart J & NESHAP, Subparts A & CC

EU	Point	Description	Const. Date
HI-13001	P69	Light Products Loading Terminal	1996

EUG 18 FCCU Flue Gas Scrubber
Subject to NSPS, Subpart J, NESHAP Subpart UUU, & OAC 252:100-19 & 35

EU	Point	Description	Const. Date
FGS-200	P70	FCCU Flue Gas Scrubber	2004

EUG 19 CO Boilers Subject to NSPS, Subparts Db & J & OAC 252:100-19 & 33

EU	Point	Description	MMBTUH	Const. Date
B-253A	P70	CO Boiler	144.0	2004
B-253B	P70	Boiler/CO Boiler	144.0	2004

EUG 20 Limited Use/Emergency Internal Combustion Engines
Subject to NSPS, Subpart IIII or JJJJ and/or NESHAP, Subpart ZZZZ

EU	Point	Make/Model Description of Use	KW (HP)	Serial #	Const. Date
EEQ-8801	P73	Detroit DMT 825D-2 Wastewater Generator	750 (1006)	4A0015	1994
P1806	P75	Cummins NT-855-F2 Fire Pond Water Pump	283 (380)	10598135	1976
P1807A	P76	Caterpillar 3412 HRM Deluge (East)	597 (800)	38S23403	2004
P1807B	P77	Caterpillar 3412 HRM Deluge (Middle)	597 (800)	38S23405	2004
P1807C	P78	Caterpillar 3412 HRM Deluge (West)	597 (800)	38S23463	2004
EG1880-01	P79	Cummins WSG-1068 Guard House Generator	85.5 (115)	0586127	2009
EG1880-02	P80	Cummins QS87-G5-NR3 Control Room Generator	100 (134)	73466046	2012
EG-ADMIN	P91	Cummins QSX15-G9 New Admin Building Generator	400 (536)	40013112	2018

EUG 21 Flare Subject to NSPS, Subpart A

EU	Point	Description	Const. Date
HI-81004	P81	Backup East Flare – 16" SASFF	< 1968

SASFF – Steam Assisted Smokeless Field Flare

EUG 22 Instrument/Plant Air Compressor
Exempt from Requirements of NESHAP, Subpart ZZZZ

EU	Point	Make/Model	hp	Serial #	Const. Date
C-80018	P82	Cummins N14-C475	500	11824120	1993

EUG 23 SRU Molten Sulfur Storage & Loading Subject to OAC 252:100-31-26

EU	Point	Description	# Arms	Const. Date
MSLA-520	P83	#1 SRU Railcar Molten Sulfur Loading Rack	1	1993
LR-SB001	P84	#2 SRU Railcar Molten Sulfur Loading Rack	3	2004
SSP520	P85	#1 SRU Molten Sulfur Storage Pit	N/A	1995
SSPTTL	P86	#1 SRU Tank Truck Molten Sulfur Loading Arm	1	2009

EUG 24 CCR Subject to NESHAP, Subpart UUU & OAC 252:100-19 & 35

EU	Point	Description	Const. Date
CCR	P87	Platformer Catalyst Regeneration Combustion Vent	1980

EUG 25 FCCU Catalyst Hopper Vent Subject to OAC 252:100-19

EU	Point	Description	Const. Date
Cat_Hop	P88	FCCU Catalyst Hopper Vent	Mod. 1981

EUG 26 WWTP Bioreactors & Associated Control Devices Subject to NESHAP (Part 61), Subpart FF, NESHAP (Part 63) Subpart CC, & NSPS, Subpart J, & OAC 252:100-19

EU	Point	Description	Const. Date
ATMV-8801	P89	WWTP Bioreactors Off-Gas Atmospheric Vent	2010
HI-8801	P90	WWTP Regenerative Thermal Oxidizer (15 MMBTUH)	2004

EUG 27 Alkylate/Gasoline Loading Station Subject to NESHAP, Subpart CC

EU	Point	Description	Const. Date
RCALOAD 900	F19	Alkylate/Gasoline Railcar Loading Station	2004

EUG 28 Ethanol Unloading Station

EU	Point	Description	Const. Date
EtOHTT	F20	Ethanol Tank Truck Unloading Station	2010
EtOHRC	F21	Ethanol Railcar Unloading Station	2012
BDTT	F22	Biodiesel Tank Truck Unloading Station	2013

EUG 29 LPG Loading & Unloading Subject to OAC 252:100-37

EU	Point	Description	Const. Date
LPG-RC-UNLOAD	P92	Railcar LPG Unloading	1990
LPG-TT-UNLOAD	P93	Tank Truck LPG Unloading	1979
LPG-RC-LOAD	P94	Railcar LPG Loading	1982
LPG-TT-LOAD	P95	Tank Truck LPG Loading	1982

EUG 30 Asphalt & No. 6 Fuel Oil Loading

EU	Point	Description	Const. Date
ASPHALT-RC-LOAD	P96	Asphalt, No. 6 Fuel Oil, Slurry, Railcar Loading	1990
ASPHALT-TT-LOAD	P97	Asphalt, No. 6 Fuel Oil, Slurry, Truck Loading	1988

EUG 31 Fugitive Equipment Leaks Subject to LDAR Programs NSPS, Subpart GGG & NESHAP, Subpart CC

EU	Point	Description
LDAR 100	F23	Area 100: Crude Unit, Crude Unit MEROX, Asphalt Blowstill Unit, and Vent Gas Recovery & Compressors
LDAR 200	F27	Area 200 - Unsat Gas Unit
LDAR 250	F28	Area 250 - Olefin Unit
LDAR 400	F29	Area 400 - NHT & Reforming Unit
LDAR 520	F30	Area 520 - SCOT, TGTU & ARU
LDAR 550	F31	Area 550 - Fuel Gas Amine Unit
LDAR 570	F32	Area 570 - #2 TGTU
LDAR 600	F33	Area 600 – DHDS Unit
LDAR 650	F34	Area 650 – CFHT Unit
LDAR 670	F35	Area 670 – Hydrocracker/Co-Processor Unit
LDAR 700	F36	Area 700 & 720 – Plant MEROX Unit
LDAR 800	F37	Area 800 – Plant Utilities System & Caustic Unit

EUG 31 Fugitive Equipment Leaks Subject to LDAR Programs NSPS, Subpart GGG & NESHAP, Subpart CC

EU	Point	Description
LDAR 810	F38	Area 810 – East & West Flare System
LDAR 880	F39	Area 880 – WWTP
LDAR 900	F40	Area 900 – Alkylation Unit
LDAR 950	F41	Area 950 – C3/C4 Splitter Unit
LDAR 2100	F42	Area 2100 – PMA Unit
LDAR LPLT	F43	Light Product Loading Terminal
LDAR Rail LPGU	F44	Railcar LPG Unloading Station
LDAR Truck LPGU	F45	Tank Truck LPG Unloading Station
LDAR Rail LPGL	F46	Railcar LPG Loading Station
LDAR Truck LPGL	F47	Tank Truck LPG Loading Station
LDAR Rail Asphalt	F48	Railcar Asphalt Loading Station
LDAR Truck Asphalt	F49	Asphalt Tank Truck Loading Station
LDAR Truck Crude	F50	Tank Truck Crude Oil Unloading Station
LDAR Alkylate	F51	VOC Railcar Loading Station
LDAR Tank farm	F52	Tank Farm Area
LDAR Biodiesel	F53	Biodiesel Unloading & Transfer

EUG 32 Fugitive Equipment Leaks Subject to LDAR Programs NSPS, Subpart GGGa & NESHAP, Subpart CC

EU	Point	Description
LDAR 260	F100	Area 260 – Gasoline Desulfurization Unit
LDAR 300	F54	Area 300 - Sat Gas Unit
LDAR 450	F55	Area 450 - BenSat Unit

EUG 33 Fugitive Equipment Leaks Subject to LDAR Program NSPS, Subpart GGG

EU	Point	Description
LDAR 150	F56	Area 150 – Hydrogen Unit
LDAR 500	F57	Area 500 - #1 SRU
LDAR 560	F58	Area 560 - #2 SRU
LDAR 580	F59	Area 580 - #2 ARU
LDAR 820	F60	Area 820 - #1 SWS
LDAR 860	F61	Area 860 – Instrument Air System

EUG 34 Fugitive Equipment Leaks Subject to LDAR Program NSPS, Subpart GGGa

EU	Point	Description
LDAR 830	F62	Area 830 - #2 SWS

EUG 35 Wastewater Plant/System[1] QQQ Fugitive Sources
Subject to NSPS, Subpart QQQ LDAR Program

EU	Point	Description
QQQ 100 (1 of 4)	F63	Area 100 (1 of 4) – Crude Unit
QQQ 100 (2 of 4)	F64	Area 100 (2 of 4) – Crude Unit MEROX
QQQ 100 (3 of 4)	F65	Area 100 (3 of 4) – Asphalt Blowstill Unit
QQQ 100 (4 of 4)	F66	Area 100 (4 of 4) – Vent Gas Recovery & Compressors
QQQ 150	F67	Area 150 – Hydrogen Unit
QQQ 200	F68	Area 200 – Unsat Gas Unit
QQQ 250	F69	Area 250 – Olefin Unit
QQQ 300	F70	Area 300 – Sat Gas Unit
QQQ 400	F71	Area 400 – NHT & Reforming Unit
QQQ 450	F72	Area 450 – BenSat Unit
QQQ 500	F73	Area 500 - #1 SRU
QQQ 520	F74	Area 520 – SCOT, TGTU & ARU
QQQ 550	F75	Area 550 – Fuel Gas Amine Unit
QQQ 560	F76	Area 560 - #2 SRU
QQQ 570	F77	Area 570 - #2 TGTU
QQQ 580	F78	Area 580 - #1 ARU
QQQ 600	F79	Area 600 – DHDS Unit
QQQ 650	F80	Area 650 – CFHT Unit
QQQ 670	F81	Area 670 – Hydrocracker/Co-Processor Unit
QQQ 700	F82	Area 700 & 720 – Plant MEROX Unit
QQQ 800	F83	Area 800 – Plant Utilities System & Caustic Unit
QQQ 810	F84	Area 810 – East & West Flare System
QQQ 820	F85	Area 820 - #1 SWS
QQQ 830	F86	Area 830 - #2 SWS
QQQ 880 (1 of 2)	F87	Area 880 – WWTP
QQQ 880 (2 of 2)	F88	Area 880 – ILS
QQQ 900	F89	Area 900 – Alkylation Unit
QQQ 950	F90	Area 950 – C3/C4 Splitter Unit
QQQ 2100	F91	Area 2100 – PMA Unit
QQQ LPLT	F92	Light Product Loading Terminal
QQQ Tank Farm	F93	Tank Farm
QQQ STG	F94	FCCU Steam Turbine Generators
QQQ WGS	F95	FCCU Flue Gas Scrubber
QQQ WHSE	F96	WHSE Yard
QQQ Bundle Pads	F97	Bundle Pads

[1] - The wastewater system consists of several different sewer systems and the wastewater treatment plant, as described in Section II (Facility Description) above. Various operating units within the Refinery are subject to the requirements of NSPS Subpart QQQ.

EUG 36 Group 1 Miscellaneous Process Vents (MPV) Subject to NESHAP, Subpart CC

EU	Point	MPV Vented to Flares or Other Control Devices
G1 MPV PCV104034A	P98	East Flare KO Drum
G1 MPV PCV104034B	P99	West Flare KO Drum
G1 MPV PCV5417	P100	Alky Acid Gas KOH Scrubber (T-901) KO Drum
G1 MPV PCV154013	P101	Hydrogen Unit (V-1501 through V-1510) PSA Offgas Pressure Control
G1 MPV BV9A(I)	P102	CCR Lock Hopper No. 1 (V-418) Purge Control (II)
G1 MPV BV49A(I)	P103	CCR Lock Hopper No. 2 (V-424) Purge Control (II)
G1 MPV BV44(I)	P104	CCR Vent Drum No. 1 (V-428) Purge Control (II)
G1 MPV BV44(II)	P105	CCR Vent Drum No. 2 (V-429) Purge Control
G1 MPV BV4	P106	CCR Vent Drum No. 3 (V-432) Purge Control
G1 MPV BV15	P107	CCR Vent Drum No. 4 (V-433) Purge Control
G1 MPV FI32552	P108	MEROX De-Sulfide Settler (V-732) Purge Control
G1 MPV BV9A(II)	P109	Reformer Recycle Gas Coalescer (Z-402) Purge Control (II)
G1 MPV BV49A(II)	P110	Reformer Booster Gas Coalescer (Z-404) Purge Control (II)

EUG 37 Sources Vented to the Fuel Gas Recovery System (FGRS) & Not Subject to NESHAP, Subpart CC

EU	Point	Sources Vented to FGRS
G1 MPV HV2527	P111	FCCU Debutanizer (T-205) Pressure Control
G1 MPV PCV824030B	P112	#1 SWS (T-82001) Pressure Control
G1 MPV PCV834051B	P113	#2 SWS (T-83001) Pressure Control
G1 MPV HV9507	P114	Alky Isostripper Receiver (V-903) Pressure Control Through KOH Scrubber (T-901)
G1 MPV PSE94139	P115	Alky CBM Surge Drum (V-923) Pressure Control Through KOH Scrubber (T-901)
G1 MPV HV9501	P116	Alky Depropanizer (V-905) Pressure Control Through KOH Scrubber (T-901)
G1 MPV PCV14071	P117	Crude Unit Fractionator Overhead Receiver (V-120) Pressure Control
G1 MPV PCV154007	P118	Hydrogen Unit Cold Separator (V-15003) Pressure Control
G1 MPV PCV154009	P119	Hydrogen Unit (V-1501 through V-1510) Hydrogen Offgas Pressure Control
G1 MPV PCV2401B	P120	FCCU Feed Surge Drum (V-201) Pressure Control
G1 MPV PV2436	P121	FCCU Fractionator Overhead Receiver (V-203) Pressure Control
G1 MPV PCV3502	P122	Sat Gas DIB Fractionator Overhead Receiver (V-304) Pressure Control
G1 MPV PCV3411B(I)	P123	Sat Gas Debutanizer Feed Surge Drum (V-305) Pressure Control
G1 MPV BV9(I)	P124	CCR Lock Hopper No. 1 (V-418) Purge Control (I)
G1 MPV BV49(I)	P125	CCR Lock Hopper No. 2 (V-424) Purge Control (I)

EUG 37 Sources Vented to the Fuel Gas Recovery System (FGRS) & Not Subject to NESHAP, Subpart CC

EU	Point	Sources Vented to FGRS
G1 MPV BV49(II)	P126	CCR Vent Drum No. 1 (V-428) Purge Control (I)
G1 MPV PCV4438B (I)	P127	NHT Feed Surge Drum (V-439) Pressure Control
G1 MPV PCV5302	P128	#1 SRU Amine Regenerator Overhead Receiver (V-501) Pressure Control
G1 MPV PCV58448	P129	#2 SRU Amine Regenerator Overhead Receiver (V-5802) Pressure Control
G1 MPV PCV6418A	P130	DHDS Feed Surge Drum (V-608) Pressure Control
G1 MPV PCV64235	P131	DHDS Fractionator Overhead Receiver (V-623) Pressure Control
G1 MPV PCV64505	P132	CFHT Fractionator Overhead receiver (V-6511) Pressure Control
G1 MPV PCV6514165	P133	CFHT recycle Gas Cyclone Separator (V-6514) Pressure Control (I)
G1 MPV PCV6514166	P134	CFHT recycle Gas Cyclone Separator (V-6514) Pressure Control (II)
G1 MPV PCV8415B	P135	General Refinery Fuel Gas Drum (V-804) Pressure Control
G1 MPV BV9(II)	P136	Reformer Recycle Gas Coalescer (Z-402) Purge Control (I)
G1 MPV BV49(III)	P137	Reformer Booster Gas Coalescer (Z-404) Purge Control (I)
G1 MPV PCV654585	P138	CFHT Flare Header Fuel Gas Purge Control (I)
G1 MPV PCV654586	P139	CFHT Flare Header Fuel Gas Purge Control (II)
G1 MPV PCV674060	P140	Hydrocracker Flare Header Fuel Gas Purge Control
G1 MPV PCV64719	P141	DHDS High Pressure Drain Drum (V-627) Pressure Control
G1 MPV PCV56463	P142	#2 SRU Hot Oil Heater Surge Drum (V-5604) Fuel Gas Purge Control
G1 MPV PCV2458	P143	FCCU Flare Header Fuel Gas Purge Control
G1 MPV FI58221	P144	#2 ARU Flare Header Fuel Gas Purge Control
G1 MPV FI56209	P145	#2 SRU Flare Header Fuel Gas Purge Control
G1 MPV 3451B(II)	P146	Sat Gas Debutanizer Overhead Receiver (V-301) Pressure Control
G1MPV FE102014	P147	Vacuum Tower Hotwell (V-105)
G1MPV FE102021	P148	Vent Gas Recovery Compressor Discharge Drum (V-10124)
G1MPV V10123	P149	Hotwell Compressor Discharge Drum (V-10123)
G1MPV PCV2451	P150	FCCU Sponge Gas Absorber (T-204)
G1MPV PCV2452B	P151	FCCU Deethanizer Overhead Receiver (V-207)
G1MPV PCV3451	P152	Sat Gas Debutanizer Overhead Receiver (V-301)
G1MPV PCV3408	P153	Sat Gas Deethanizer Overhead Receiver (V-302)
G1MPV PV73	P154	NHT Stripper Overhead Receiver (V-402)
G1MPV PV36A	P155	NHT Stripper Cold Separator (V-436)
G1MPV PV6422	P156	DHDS Low Pressure Receiver (V-602)
G1MPV PV6463	P157	DHDS Stripper Overhead Receiver (V-622)

EUG 37 Sources Vented to the Fuel Gas Recovery System (FGRS) & Not Subject to NESHAP, Subpart CC

EU	Point	Sources Vented to FGRS
G1MPV FV652170	P158	CFHT Recycle Gas Amine Contactor Purge (T-6501)
G1MPV PV654410	P159	CFHT Cold Flash Drum (V-6510)
G1MPV PV654490	P160	CFHT Offgas After Cooler Receiver (V-6522)
G1MPV FE832016	P161	#2 SWS Overhead Receiver (V-83001)
G1MPV FE822019	P162	#1 SWS Overhead Receiver (V-82001)
G1MPV PV4434B (II)	P163	NHT Feed Surge Drum (V-439)
G1MPV PV64235	P164	DHDS Fractionator Overhead Receiver (V-623)
G1MPV PV3411A	P165	Sat Gas Debutanizer Feed Surge Drum (V-305)
G1MPV PCV55423	P166	MDEA Rich Amine Flash Drum (V-55005)
G1MPV PV245	P167	Reformer Debutanizer Overhead Receiver (V-408)
G1MPV PV1608	P168	Reformer Net Gas Absorber Overhead (T-404)
G1MPV PV45448	P169	ISOM Net Gas Caustic Scrubber Overhead (T-452)
G1MPV PV55401	P170	Amine Unit Offgas Scrubber Overhead (V-553)
G1MPV PCV154009	P171	PSA Excess Hydrogen (V-1501 through V-1510)
G1MPV PCV9477	P172	PSA Excess Hydrogen (V-1501 through V-1510)
G1MPV PV9447	P173	Propane Scrubber Overhead (V-909 & V-910)
G1MPV PV904321	P174	Dehydrator Feed Surge Drum (V-924)
G1MPV PCV8412	P175	Reformer Fuel Gas Drum (V-412)
G1MPV PV14708	P176	Hotwell Compressor Separator (V-10123)
G1MPV PCV152012	P177	PSA Offgas (V-1501 through V-1510)
G1MPV PV604121	P178	DHDS Stripper Overhead Receiver Vent #2
G1 MPV PM199-B1A1	P179	Bensat Closed Collection Drain Drum (V-4507) Continuous Flare Pressure Control Valve
G1 MPV P45115-A1A1	P180	Bensat Flare Header Continuous Purge Gas Valve
G1 MPV PV-45441	P181	BenSat Overhead Receiver (V-452) Pressure Control Valve
G1 MPV PCV BSP2	P182	Makeup Hydrogen Compressor Discharge Drum
G1 MPV PCV BSP5	P183	Stabilizer Reboiler Pressure Control
G1 MPV PCV BSP6	P184	Splitter Reboiler Pressure Control

EUG 38 Group 2 Miscellaneous Process Vents (MPV) Subject to NESHAP, Subpart CC

EU	Point	Sources Vented to FGRS
GII MPV V150004	P185	Hydrogen Unit Deaerator Vent (V-150004)

EUG 39 PMA Unit Scrubber & ASV Mist Eliminator Subject to NESHAP, Subpart LLLLL

EU	Point	Description
PMA SCRUB VENT	P186	PMA Unit Storage Tanks Nitrogen Blanket Scrubber
ASV Mist Eliminator	P226	Asphalt Storage Tanks Mist Eliminator

EUG 40 WWTP Transfer Pump's ICE
Subject to NSPS, Subpart IIII and/or NESHAP, Subpart ZZZZ

EU	Point	Make/Model	KW (HP)	Serial #	Const. Date
P850A	P187	Deutz F4914	61.5 (82.5)	8754882	2006
P850B	P188	Deutz F4912	54 (72.5)	8377851	1995
P850C	P189	John Deere 4045DF 270B	60 (80)	PE4045D398133	2004
P850D	P190	John Deere 4045TF 280B	63 (84)	PE4045L124293	2010
P850E	P191	John Deere 4045TF 275B	86 (116.4)	PE4045T308137	2003
FWPE-1	P226	Caterpillar 3406C	345 (460)	3ER07868	12/12/2002

EUG 41 Startup, Shutdown, and Maintenance (SSM) Activities

The nature of refining operations requires certain activities that are outside normal continuous operations. These activities result in air emissions that exceed the emission rate of normal operations.

EU	Point	Activity
FGS-200	P70	FCCU Startup
FGS-200	P70	FCCU Shutdown
HI-81001	P63	West Flare, CFHT & Hydrocracker Shutdown
HI-81003	P65	East Flare, C-114 Shutdown
HI-81001 & HI-81003	P63 & P65	West & East Flares, Misc. Refinery Unit Start Up/Shut Down
RTDFUG	Fugitive	Refinery Turnaround Depressurization (Fugitive)
TDCSMFUG	Fugitive	Tank Degassing, Changes in Service, Maintenance

EUG 42A CFHT Induced Draft Cooling Tower
900-hp, 310 MMBTUH, 20,000 GPM, Heat Exchangers W/HAP Concentration >5%, W/Pressure > Cooling Water Pressure, & Subject to NESHAP, Subpart CC

EU	Point	Heat Exchangers
C-150001	P192	E-607A – DHDS Stripper Overhead Light Naphtha Condenser
		E-607B – DHDS Stripper Overhead Light Naphtha Condenser
		E-60034 – DHDS Fractionator Heavy Naphtha Product Cooler
		E-205A – FCCU Fractionator Overhead Light Naphtha Condenser
		E-205B – FCCU Fractionator Overhead Light Naphtha Condenser
		E-205C – FCCU Fractionator Overhead Light Naphtha Condenser
		E-205D – FCCU Fractionator Overhead Light Naphtha Condenser
		E-205E – FCCU Fractionator Overhead Light Naphtha Condenser
		E-205F – FCCU Fractionator Overhead Light Naphtha Condenser
		E-210A – FCCU Fractionator Wet Gas Condenser
		E-210B – FCCU Fractionator Wet Gas Condenser
		E-210C – FCCU Fractionator Wet Gas Condenser
		E-210D – FCCU Fractionator Wet Gas Condenser
		E-217A – FCCU Debutanizer Gasoline Product Cooler
		E-217B – FCCU Debutanizer Gasoline Product Cooler

EUG 42B Ceramic Induced Draft Cooling Tower
1,200-hp, 273 MMBTUH, 8,500 GPM, Heat Exchangers W/HAP Concentration >5%, W/Pressure > Cooling Water Pressure, & Subject to NESHAP, Subpart CC

EU	Point	Heat Exchangers
C-1501	P193	E-10043 - Vent Gas Condenser
		E-10044 - Vent Gas Condenser
		E-101 – Fractionator Heavy Naphtha Product Cooler
		E-111A – Fractionator Light Naphtha Condenser
		E-111B – Fractionator Light Naphtha Condenser
		E-111C – Fractionator Light Naphtha Condenser
		E-111D – Fractionator Light Naphtha Condenser
		E-113A – Fractionator Light Naphtha Condenser
		E-113B – Fractionator Light Naphtha Condenser
		E-113C – Fractionator Light Naphtha Condenser
		E-113D – Fractionator Light Naphtha Condenser
		E-116A – Fractionator Heavy Naphtha Product Cooler
		E-116B – Fractionator Heavy Naphtha Product Cooler
		E-116C – Fractionator Heavy Naphtha Product Cooler
		E-116D – Fractionator Heavy Naphtha Product Cooler
		E-304A – Debutanizer Naphtha Product Cooler
		E-304B – Debutanizer Naphtha Product Cooler
		E-304C – Debutanizer Naphtha Product Cooler
		E-403 – Light Naphtha Condenser
		E-405A – Splitter Naphtha Product Cooler
		E-411A – Naphtha Reformer Reactor Product Cooler
		E-411B – Naphtha Reformer Reactor Product Cooler
		E-416 – Debutanizer Heavy Reformate Product Cooler
		E-418 – Debutanizer Light Reformate Product Cooler

EUG 42C Alkylation Induced Draft Cooling Tower
700-hp, 248 MMBTUH, 16,000 GPM, Heat Exchangers W/HAP Concentration >5% W/Pressure > Cooling Water Pressure, & Subject to NESHAP, Subpart CC

EU	Point	Heat Exchangers
C-150005	P194	E-903A – Alkylate Product Cooler
		E-903B – Alkylate Product Cooler
		E-907A – Reactor Alkylate Recycle Cooler
		E-907B – Reactor Alkylate Recycle Cooler
		E-907C – Reactor Alkylate Recycle Cooler
		E-907D – Reactor Alkylate Recycle Cooler
		R-901 – Alkylation Reactor/Heat Exchanger
		R-902 – Alkylation Reactor/Heat Exchanger

EUG 42D STG Induced Draft Cooling Tower
600-hp, 214 MMBTUH, 25,800 GPM, Heat Exchangers W/HAP Concentration >5%, W/Pressure > Cooling Water Pressure, & Subject to NESHAP, Subpart CC

EU	Point	Heat Exchangers
C-150006	P195	E-81004 – FGR Naphtha Slop Product Cooler
		E-10043 - Vent Gas Condenser
		E-10044 - Vent Gas Condenser
		E-101 – Fractionator Heavy Naphtha Product Cooler
		E-111A – Fractionator Light Naphtha Condenser
		E-111B – Fractionator Light Naphtha Condenser
		E-111C – Fractionator Light Naphtha Condenser
		E-111D – Fractionator Light Naphtha Condenser
		E-113A – Fractionator Light Naphtha Condenser
		E-113B – Fractionator Light Naphtha Condenser
		E-113C – Fractionator Light Naphtha Condenser
		E-113D – Fractionator Light Naphtha Condenser
		E-116A – Fractionator Heavy Naphtha Product Cooler
		E-116B – Fractionator Heavy Naphtha Product Cooler
		E-116C – Fractionator Heavy Naphtha Product Cooler
		E-116D – Fractionator Heavy Naphtha Product Cooler
		E-304A – Debutanizer Naphtha Product Cooler
		E-304B – Debutanizer Naphtha Product Cooler
		E-304C – Debutanizer Naphtha Product Cooler
		E-403 – Light Naphtha Condenser
		E-405A – Splitter Naphtha Product Cooler
		E-411A – Naphtha Reformer Reactor Product Cooler
		E-411B – Naphtha Reformer Reactor Product Cooler
		E-416 – Debutanizer Heavy Reformate Product Cooler
		E-418 – Debutanizer Light Reformate Product Cooler

EUG 43 Bypass Pressure Control Valves (BPCV) & Bypass Block Valves (BBV) Subject to NESHAP, Subpart UUU

EU	Point	Sources Routed to Flare Gas Recovery System
PV5401A BPCV	P196	Amine Acid Gas Bypass of #1 SRU
PV824030 BPCV	P197	#1 SWS Acid Gas Bypass of SRU(s)
PV834015 BPCV	P198	#2 SWS Acid Gas Bypass of SRU(s)
PV57409 BPCV	P199	Amine Acid Gas Bypass of #2 SRU
PV58448 BPCV	P200	Amine Acid Gas Bypass of #2 SRU
PSV-55470 4” BBV	P201	4” BBV Around PSV-55470
PSV-55471 4” BBV	P202	4” BBV Around PSV-55471
PSV-55423 1.5” BBV	P203	1.5” BBV Around PSV-55423
PV-55423 2” BBV	P204	2” BBV at Discharge of PV-55423
PSV-55462 2” BBV	P205	2” BBV Around PSV-55462
PSV-55305 1” BBV	P206	1” BBV Around PSV-55305
PSV-56441 2” BBV	P207	2” BBV Around PSV-56441

EU	Point	Sources Routed to Flare Gas Recovery System
PSV-56442 1.5” BBV	P208	1.5” BBV Around PSV-56442
PSV-56443 1.5” BBV	P209	1.5” BBV Around PSV-56443
PSV-565754 2” BBV	P210	2” BBV Around PSV-565754
PSV-57465 1.5” BBV	P211	1.5” BBV Around PSV-57465
PSV-57461 3” BBV	P212	3” BBV Around PSV-57461
PSV-57409 3” BBV	P213	3” BBV Around PSV-57409
PSV-58406 4” BBV	P214	4” BBV Around PSV-58406
PSV-58438 3” BBV	P215	3” BBV Around PSV-58438
PSV-584064 1.5” BBV	P216	1.5” BBV Around PSV-584064
V-5804 3” BBV	P217	3” BBV on V-5804
PSV-584067 1” BBV	P218	1” BBV Around PSV-584067
V-82001 3” BBV	P219	3” BBV on V-82001
PSV-824029 3” BBV	P220	3” BBV Around PSV-824029
V-83001 4” BBV	P221	4” BBV on V-83001
PSV-834015B 4” BBV	P222	4” BBV Around PSV-834015B
PSV-834014 2” BBV	P223	2” BBV Around PSV-834014
PSV-834022 1.5” BBV	P224	1.5” BBV Around PSV-834022
CCR Scrubber BBV	P225	CCR Regenerator Flue Gas Bypass Atmospheric Vent Maintained Under Car Seal

Insignificant Activities (ISA)

PMA Unit Polymer Unloading & Storage Silos
Company Vehicle/Equipment Fueling Station
RCRA North Yard Bin Storage Area
DHDS Catalyst Change-Out Area
CFHT Catalyst Change-Out Area
Hydrocracker Catalyst Change-Out Area
SRU Catalyst Change-Out Area
NHT Catalyst Change-Out Area
Reformer Catalyst Change-Out Area
Bensat Catalyst Change-Out Area
East Bundle Pad
West Bundle Pad
Tank Truck Crude Oil Unloading Station
Railcar Toluene Unloading Station
Other sources/equipment meeting definition of ISA in OAC 252:100-8-2

Storage Vessels that Qualify as Insignificant Activities/Trivial Activities

EU	Contents	Barrels	Const. Date
T-451	Perchloroethylene	74	1974
T-551	MDEA	91	1991
T-811	Spent Caustic	1,007	1992
T-812	Spent Caustic	1,007	1992
T-813	Spent Caustic	1,007	1992

EU	Contents	Barrels	Const. Date
T-814	Spent Caustic	1,007	1992
T-8803	RCRA Remediation Trench Oil/Water	202	2001
T-8804	RCRA Remediation Trench Oil	202	2001
T-210001	Polymer Asphalt	19	1996
T-210002	10 % H_3PO_4	9,517	1996
TK-13005	Fuel Additives	49	1993
TK-13007	Fuel Additives	49	1996
TK-13008	Fuel Additives	49	1996
TK-13009	Fuel Additives	49	1996
V-523	Amine	91	1993
V-815	Wastewater Centrifuge Solids	1,731	1968
JFP1	Refinery Vehicle Refueling Gasoline	52	1993
JFP2	Refinery Vehicle Refueling Red Dye	11	1993
JFP3	Refinery Vehicle Refueling Diesel (Off-Road)	22	1993
TK-90001	Spent KOH/KF	1,678	2008
EWCPTK-1	Diesel Fuel	21	2004
EWCPTK-2	Diesel Fuel	21	2004
EWCPTK-3	Diesel Fuel	21	2004
T-1191	Slop Oil	200	2009

Trivial Activities (TA)
South 40 WWTP Ponds
Treated Process Water Pond 002
Treated Process Water Pond 003
Treated Process Water Northwest Pond
Refinery Internal Firefighting Training Area
Maintenance Department Cutting/Grinding/Welding Activities
Chigger Hill Equipment Fabrication and De-Commissioning/Lay Down Yard
Warehouse Yard Bulk-Chemical/Tote/Cylinder/Drum Storage Yard
Light Product Loading Terminal Fuel Additive Storage Totes/Tanks
Aerosol Can Disposal Station
Gasoline blender QA/QC operations
QA/QC Laboratories
Land Treatment Unit
Other approved sources meeting definition of TA in OAC 252:100-8-2

SECTION V. EMISSIONS

The quantification of emissions and the assumptions utilized are discussed in detail in this section. Emissions from the facility were based on the applicable standards and the equipment involved. Emission estimates are not exact but are considered to be representative, because in some cases a group of emission units may be subject to a cap on emissions and the actual distribution of those emissions within the EUs covered may be different than shown here. This permit will supersede any conditions of the previous operating permits that affect the EU incorporated into this permit.

Individual source emissions are provided below for the purpose of identifying their contribution to the facility wide VOC cap established for the tanks.

Green House Gas (GHG) emissions (CO_{2e}) are all based on the methodologies presented in 40 CFR Part 98, Subpart Y and are included for the following:

- CO_2, CH_4, and N_2O combustion emissions from stationary combustion units and each flare;
- CO_2, CH_4, and N_2O coke burn-off emissions from each catalytic cracking unit, fluid coking unit, and catalytic reforming unit;
- CO_2 process emissions from each on-site sulfur recovery plant;
- CO_2, CH_4, and N_2O emissions from each coke calcining unit;
- CO_2 and CH_4 emissions from asphalt blowing operations;
- CH_4 emissions from equipment leaks, storage tanks, loading operations, delayed coking units, and uncontrolled blowdown systems;
- CO_2, CH_4, and N_2O emissions from each process vent not previously included; and
- CO_2 emissions from non-merchant hydrogen production process units.

GHG emissions from the storage vessels were only calculated for the crude oil storage tanks and were based on the default methane factor of 0.1 metric tons per million barrels and the throughput of the refinery of 97.2 MBPD. Total CO_{2e} for the crude oil storage tanks was estimated at 98 TPY.

EMISSIONS FROM TANKS: EUGs 1A, 1B, 2A, 2B, 3, 5, 6, and 7

Emissions from the tanks in EUGs 1A through 7 are based on the EPA's TANKS 4.0.9d program, the characteristics of the contents, and estimated throughput. Emissions are shown in the following tables.

EUG 1A and 1B VOC Emissions

		Throughput	**VP**	**Emissions**
EU	**Contents**	**BPY**	**psia**	**TPY**
T-1018R	Alkylate & Gasoline	9,490,000	2.800	0.52
T-1019	Alkylate & Gasoline	2,555,000	RVP 15	14.30
T-1082 T-1083 T-1084	Crude Oil	36,500,000	RVP 5	11.26
T-1115	Gasoline W/Ethanol	11,205,500	RVP 10.5	6.29
T-1116	Gasoline W/Ethanol	9,510,400	RVP 10.5	6.29
T-1123	Gasoline /Diesel	2,735,640	RVP 10.5	9.14
T-1124	Gasoline	4,920,856	RVP 10.5	9.66
T-1125	Gasoline	7,500,000	RVP 10.5	12.00
T-1126	Gasoline	7,500,000	RVP 10.5	12.00
T-1130	Gasoline	10,402,500	RVP 15	26.76
T-1131	Gasoline/FCCU Gasoline/ ISOM/Hydrocracker Naptha	6,703,616.5	11.00	5.71
T-1132	Reformate	12,514,286	11.00	7.83
Total				**121.76**

EUG 2A and 2B VOC Emissions

		Throughput	VP	Emissions
EU	**Contents**	**BPY**	**psia**	**TPY**
T-1121	Diesel/Kerosene	365,800	0.008	0.42
T-1127	Diesel/Kerosene	3,300,000	0.008	1.56
T-1128	Diesel/Kerosene	3,300,000	0.008	1.56
T-1129	Diesel/Kerosene	61,264	0.008	0.03
T-1141	Diesel/Kerosene	3,578,477	0.080	1.91
T-1142	Diesel/Kerosene	2,391,914	0.080	1.27
T-1153	FCCU Charge	10,950,222	0.002	1.75
T-1156	FCCU Slurry	442,319	0.028	0.98
T-5801	Amine	10,667,000	0.002	0.40
TK-13006	Fuel Additives	100,00	0.014	0.01
TK-90002	ASO	47,212	0.313	0.43
Total				**10.32**

EUG 3 VOC Emissions

		Throughput	VP	Emissions
EU	**Contents**	**BPY**	**psia**	**TPY**
T-1155	Heavy Naphtha/Distillate	12,045,000	1.322	3.13
T-1152	Sour Water	2,131,286	0.349	0.31
T-100160	Ethanol	3,000,000	1.218	0.55
Total				**3.99**

EUG 5 VOC Emissions

			Throughput	VP	Emissions
EU	**Tank**	**Contents**	**BPY**	**psia**	**TPY**
T-1102	T-1102	Asphalt/Gas Oil	1,100,000	0.014	1.50
T-1113	T-1113	Gas Oil/Asphalt	1,200,548	0.014	1.62
T-1118	T-1118	Asphalt	733,674	0.014	1.35
T-1151	T-1151	Asphalt	1,893,114	0.014	2.56
T-100149	T-100149	Asphalt Flux	1,400,000	0.135	1.77
T-100150	T-100150	Asphalt Base	2,800,000	0.135	2.08
P-26 [1]	T-210003	Asphalt Flux	1,398,970	0.041	1.33
	T-210004	PMA Rxn	2,100,000	0.041	2.24
	T-210005	PMA Rxn	2,100,000	0.041	2.24
	T-210006	PMA	1,400,000	0.041	2.21
	T-210007	PMA	1,400,000	0.041	2.21
	T-210008	PMA	1,400,000	0.041	2.44
Total					**23.55**

1) EU P-26 includes the group of tanks indicated, which are configured to allow liquids to flow freely between the tanks and which have vent lines from each tank tied into a common manifold that routes vapors to the V-210001 PMA Vent Gas Scrubber, P-26, emission point P186.

EUG 6 VOC Emissions

EU	Contents	Throughput BPY	VP psia	Emissions TPY
V-8801	Wastewater	9,560,914	RVP 4.5	7.34
V-8802	Wastewater	9,560,914	RVP 4.5	7.34
Total				**14.68**

EUG 7 VOC Emissions

EU	Contents	Throughput BPY	VP psia	Emissions TPY
T-83001	Sour Water	2,565,575	0.010	4.79

EUG 8 Emissions

The emissions from T-5602 are vented to the SRU incinerator (EUG 15) and are incorporated into that limit as SO_2. Potential emissions are based on a H_2S concentration of 8,000 ppmv (based on historical analyses of sulfur pit sweep vapors ~2,000 ppmv plus a safety factor of four), the density of molten sulfur (124.8 lb/CF) and a run-down rate of 12,100 lb/hr of molten sulfur (130 LTD).

Criteria Pollutant Emissions from EUG 9

	NO_X		CO		PM_{10}		SO_2		VOC	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
B-801[1]	9.24	31.13	7.76	26.15	0.70	2.37	2.43	10.66	0.51	1.71
B-802[1]	11.45	38.56	9.61	32.39	0.87	2.93	3.01	13.20	0.63	2.12
B-803[1]	11.06	37.27	9.29	31.31	0.84	2.83	2.91	12.76	0.61	2.05
H-102A[2]	7.20	31.54	17.13	57.71	1.55	8.51	5.37	23.52	1.12	3.78
H-102B[2]	6.08	26.61	14.45	48.70	1.31	7.19	4.53	19.85	0.95	3.19
H-103[1]	24.85	83.71	10.98	37.01	0.99	3.35	3.44	15.08	0.72	2.42
H-201[1]	28.26	95.21	12.49	42.09	1.13	3.81	3.92	17.16	0.82	2.76
H-403[1]	12.58	42.38	10.57	35.60	0.96	3.22	3.31	14.51	0.69	2.33
H-404/5[1]	12.66	42.64	10.63	35.82	0.96	3.24	3.34	14.61	0.70	2.35
H-601[1]	7.46	25.12	6.26	21.10	0.57	1.91	1.96	8.60	0.41	1.38
H-603[2]	8.28	36.28	5.21	22.81	1.22	4.10	4.21	18.45	0.88	2.96
H-6502[2]	3.26	14.27	2.19	9.61	0.53	1.77	1.82	7.98	0.38	1.28
H-15001[2]	19.61	85.88	9.80	42.94	3.17	10.67	10.97	48.05	2.29	7.72
Totals	**162.0**	**590.6**	**126.4**	**443.2**	**14.80**	**55.90**	**51.22**	**224.4**	**10.71**	**36.05**

[1] - Emissions are based on the heat input ratings HHV (MMBTUH) and the following emission factors:

NO_X, CO, PM_{10}, & VOC - AP-42 (7/98), Section 1.4 emissions factors plus 30% for the short term emission rates (lb/hr); for heaters rated greater than 100 MMBTUH (H-103 and H-201) the uncontrolled post-NSPS NO_X emission factors plus 30% for the short term emission rates (lb/hr) are used; and

SO_2 - A fuel-gas H_2S concentration of 0.1 grain/DSCF and a HHV of 800 BTU/SCF (0.0336 lb/MMBTU).

[2] - Emissions are based on the heat input ratings HHV (MMBTUH) and the following emission factors:

NO_X emissions are based on the following manufacturer's specifications: H-102A - 0.045 lb/MMBTU, H-102B - 0.045 lb/MMBTU, H-603 - 0.066 lb/MMBTU, and H-6502 and H-15001 - 0.06 lb/MMBTU;

CO - AP-42 (7/98), Section 1.4 emissions factors plus 30% for the short term emission rates (lb/hr); except for H-603, H-6502, and H-15001 which are based on the following manufacturer's specifications: 0.0415, 0.0404, and 0.03 lb/MMBTU, respectively;

PM_{10}, & VOC - AP-42 (7/98), Section 1.4 emissions factors plus 30% for the short term emission rates (lb/hr); and

SO_2 - A fuel-gas H_2S concentration of 0.1 grain/DSCF and a HHV of 800 BTU/SCF (0.0336 lb/MMBTU).

GHG Emissions from EUG 9

	CO_2		N_2O (CO_{2e})		CH_4 (CO_{2e})		CO_{2e}	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
B-801[1]	7,994	35,014	5	21	2	7	8,001	35,042
B-802[1]	9,902	43,370	6	26	2	9	9,910	43,405
B-803[1]	9,571	41,921	6	25	2	8	9,579	41,954
H-102A[1]	17,642	77,273	11	46	4	15	17,657	77,334
H-102B[1]	14,886	65,199	9	39	3	13	14,898	65,251
H-103[1]	11,313	49,551	7	30	2	10	11,322	49,591
H-201[1]	12,868	56,361	8	34	3	11	12,879	56,406
H-403[2]	10,936	47,901	6	28	4	17	10,946	47,946
H-404/5[2]	11,003	48,193	7	29	4	17	11,014	48,239
H-601[1]	6,451	28,253	4	17	1	6	6,456	28,276
H-603[1]	13,838	60,611	8	36	3	12	13,849	60,659
H-6502[1]	5,987	26,225	4	16	1	5	5,992	26,246
H-15001[3]	10,295	45,092	6	27	4	18	10,305	45,137
H-15001[4]	49,182	215,415	16	71	2	8	49,200	215,494
Totals	**191,868**	**840,379**	**103**	**445**	**37**	**156**	**192,008**	**840,980**

[1] - Emissions are based on the heat input ratings HHV (MMBTUH) and the following emission factors:

The refinery fuel gas maximum CO_2 emission factor of 110.3 lb/MMBTU based on the composition of the refinery fuel gas over the last nine years.

The default N_2O emission factor for natural gas from Table C-2 to Subpart C of Part 98.

The default CH_4 emission factor for natural gas from Table C-2 to Subpart C of Part 98 times the maximum percent CH_4 in the refinery fuel gas over the last nine years.

[2] - Emissions are based on the heat input ratings HHV (MMBTUH) and the following emission factors:

The Platformer fuel gas maximum CO_2 emission factor of 110.8 lb/MMBTU based on the composition of the Platformer fuel gas over the last nine years.

The default N_2O emission factor for natural gas from Table C-2 to Subpart C of Part 98.

The default CH_4 emission factor for natural gas from Table C-2 to Subpart C of Part 98 times the maximum percent CH_4 in the Platformer fuel gas over the last nine years.

[3] - Emissions are based on a portion of the heat input rating (89.2 MMBTUH) HHV and the following emission factors:

The natural gas maximum CO_2 emission factor of 115.4 lb/MMBTU based on the composition of the natural gas over the last five years.

The default N_2O emission factor for natural gas from Table C-2 to Subpart C of Part 98.

The default CH_4 emission factor for natural gas from Table C-2 to Subpart C of Part 98 times the maximum percent CH_4 in the natural gas over the last nine years.

[4] - Emissions are based on the remaining portion of the heat input rating (237.6 MMBTUH) HHV and the following emission factors:

The PSA off-gas average CO_2 emission factor of 207.0 lb/MMBTU.

The default N_2O emission factor for natural gas from Table C-2 to Subpart C of Part 98.

The default CH_4 emission factor for natural gas from Table C-2 to Subpart C of Part 98 times the percent CH_4 in the PSA off-gas.

Criteria Pollutant Emissions from EUG 10

	NO_X		CO		PM_{10}		SO_2		VOC	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
H-6501[1]	3.99	17.47	4.03	17.65	0.75	3.29	3.35	14.67	0.54	2.37

[1] - Emissions are based on the heat input ratings HHV (MMBTUH) and the following emission factors:

NO_X emissions are based on the following specification provided by the manufacturer: H-6501 - 0.0400 lb/MMBTU;

CO emissions are based on the following specification provided by the manufacturer: H-6501 - 0.0404 lb/MMBTU;

PM_{10}, & VOC - AP-42 (7/98), Section 1.4 emissions factors plus 30% for the short term emission rates (lb/hr); and

SO_2 - A fuel-gas H_2S concentration of 0.1 grain/DSCF and a HHV of 800 BTU/SCF (0.0336 lb/MMBTU).

GHG Emissions from EUG 10

	CO_2		N_2O (CO_{2e})		CH_4 (CO_{2e})		CO_{2e}	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
H-6501[1]	10,993	48,150	7	29	2	10	11,002	48,189

[1] - Emissions are based on the heat input ratings HHV (MMBTUH) and the following emission factors:

The refinery fuel gas maximum CO_2 emission factor of 110.3 lb/MMBTU based on the composition of the refinery fuel gas over the last nine years.

The default N_2O emission factor for natural gas from Table C-2 to Subpart C of Part 98.

The default CH_4 emission factor for natural gas from Table C-2 to Subpart C of Part 98 times the maximum percent CH_4 in the refinery fuel gas over the last nine years.

Criteria Pollutant Emissions from EUG 11

	NO_X		CO		PM_{10}		SO_2		VOC	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
H-101	3.93	13.23	3.30	11.11	0.30	1.01	1.03	4.53	0.22	0.73
H-301	2.75	9.28	2.31	7.79	0.21	0.71	0.73	3.18	0.15	0.51
H-401A	2.04	6.87	1.71	5.77	0.16	0.52	0.54	2.35	0.11	0.38
H-401B	1.89	6.36	1.58	5.34	0.14	0.48	0.50	2.18	0.10	0.35
H-402A	1.77	5.97	1.49	5.01	0.13	0.45	0.47	2.04	0.10	0.33
H-402B	2.01	6.79	1.69	5.70	0.15	0.52	0.53	2.32	0.11	0.37
H-406	3.57	12.02	3.00	10.10	0.27	0.91	0.93	4.12	0.20	0.66
H-411	3.57	12.02	3.00	10.10	0.27	0.91	0.92	4.05	0.20	0.66
H-901	7.65	25.76	6.42	21.64	0.58	1.96	2.01	8.82	0.42	1.42
H-1016	0.61	2.06	0.51	1.73	0.05	0.16	0.16	0.71	0.03	0.11
H-6701	0.71	3.10	1.26	4.26	0.11	0.39	0.40	1.74	0.08	0.28
Totals	**30.50**	**103.46**	**26.27**	**88.55**	**2.37**	**8.02**	**8.22**	**36.04**	**1.72**	**5.80**

Emissions are based on the heat input ratings HHV (MMBTUH) and the following emission factors:

NO_X, CO, PM_{10}, & VOC - AP-42 (7/98), Section 1.4 emissions factors plus 30% for the short term emission rates (lb/hr) except for H-6701 for which NO_X emissions are based on manufacturer's data: 0.06 lb/MMBTU.

SO_2 - A fuel-gas H_2S concentration of 0.1 grain/DSCF and a HHV of 800 BTU/SCF (0.0336 lb/MMBTU).

GHG Emissions from EUG 11

	CO_2		N_2O (CO_{2e})		CH_4 (CO_{2e})		CO_{2e}	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
H-101 [1]	3,396	14,875	2	9	1	3	3,399	14,887
H-301 [1]	2,382	10,432	1	6	1	2	2,384	10,440
H-401A [2]	1,773	7,765	1	5	1	3	1,775	7,773
H-401B [2]	1,640	7,183	1	4	1	3	1,642	7,190
H-402A [2]	1,540	6,746	1	4	1	2	1,542	6,752
H-402B [2]	1,751	7,668	1	5	1	3	1,753	7,676
H-406 [2]	3,103	13,589	2	8	1	5	3,106	13,602
H-411 [2]	3,103	13,589	2	8	1	5	3,106	13,602
H-901 [1]	6,616	28,977	4	17	1	6	6,621	29,000
H-1016 [1]	529	2,318	<1	1	<1	1	13,849	2,320
H-6701 [1]	1,301	5,699	1	3	0	1	1,302	5,703
Totals	**27,134**	**118,841**	**16**	**70**	**9**	**34**	**40,479**	**118,945**

[1] - Emissions are based on the heat input ratings HHV (MMBTUH) and the following emission factors:

The refinery fuel gas maximum CO_2 emission factor of 110.3 lb/MMBTU based on the composition of the refinery fuel gas over the last nine years.

The default N_2O emission factor for natural gas from Table C-2 to Subpart C of Part 98.

The default CH_4 emission factor for natural gas from Table C-2 to Subpart C of Part 98 times the maximum percent CH_4 in the refinery fuel gas over the last nine years.

[2] - Emissions are based on the heat input ratings HHV (MMBTUH) and the following emission factors:

The Platformer fuel gas maximum CO_2 emission factor of 110.8 lb/MMBTU based on the composition of the Platformer fuel gas over the last nine years.

The default N_2O emission factor for natural gas from Table C-2 to Subpart C of Part 98.

The default CH_4 emission factor for natural gas from Table C-2 to Subpart C of Part 98 times the maximum percent CH_4 in the Platformer fuel gas over the last nine years.

Criteria Pollutant Emissions from EUG 12

	NO_X		CO		PM_{10}		SO_2		VOC	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
H-100024	0.86	2.96	1.45	4.87	0.13	0.44	0.45	1.98	0.09	0.32
H-210001	1.55	5.24	1.31	4.40	0.12	0.40	0.08	0.35	0.09	0.29
H-5602	0.98	4.29	2.14	7.21	0.19	0.65	0.67	2.94	0.14	0.47
Totals	**3.39**	**12.49**	**4.90**	**16.48**	**0.44**	**1.49**	**1.20**	**5.27**	**0.32**	**1.08**

Emissions are based on the heat input ratings HHV (MMBTUH) and the following emission factors:

NO_X, CO, PM_{10}, & VOC - AP-42 (7/98), Section 1.4 emissions factors plus 30% for the short term emission rates (lb/hr) except for H-5602 for which NO_X emissions are based on manufacturer's data: 0.050 lb/MMBTU.

SO_2 - For H-100024 and H-5602, a fuel-gas H_2S concentration of 0.1 grain/DSCF and a HHV of 800 BTU/SCF (0.0336 lb/MMBTU); and For H-210001, a fuel-gas H_2S concentration of 0.025 grains/DSCF and a HHV of 1,020 BTU/SCF (0.0066 lb/MMBTU) was used.

GHG Emissions from EUG 12

	CO_2		N_2O (CO_{2e})		CH_4 (CO_{2e})		CO_{2e}	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
H-100024 [1]	1,489	6,520	1	4	0	1	1,490	6,525
H-210001 [2]	1,408	6,165	1	4	1	3	1,410	6,172
H-5602 [1]	2,205	9,659	1	6	0	2	2,206	9,667
Totals	**5,102**	**22,344**	**3**	**14**	**1**	**6**	**5,106**	**22,364**

[1] - Emissions are based on the heat input ratings HHV (MMBTUH) and the following emission factors:

The refinery fuel gas maximum CO_2 emission factor of 110.3 lb/MMBTU based on the composition of the refinery fuel gas over the last nine years.

The default N_2O emission factor for natural gas from Table C-2 to Subpart C of Part 98.

The default CH_4 emission factor for natural gas from Table C-2 to Subpart C of Part 98 times the maximum percent CH_4 in the refinery fuel gas over the last nine years.

[2] - Emissions are based on the heat input ratings HHV (MMBTUH) and the following emission factors:

The natural gas maximum CO_2 emission factor of 115.4 lb/MMBTU based on the composition of the natural gas over the last five years.

The default N_2O emission factor for natural gas from Table C-2 to Subpart C of Part 98.

The default CH_4 emission factor for natural gas from Table C-2 to Subpart C of Part 98 times the maximum percent CH_4 in the natural gas over the last nine years.

Criteria Pollutant Emissions and GHG Emissions from EUG 13

	NO_X	CO	$PM_{2.5}$	SO_2	VOC	CO_{2e}
Emission Unit	**TPY**	**TPY**	**TPY**	**TPY**	**TPY**	**TPY**
H-2601	3.47	4.80	0.43	0.44	0.31	6,277

Potential emissions are based on the firing rate (13.2 MMBTUH), the fuel heat value (918 BTU/SCF HHV) and the following emission factors:

i) NO_X: 0.06 lb/MMBTU, vendor guarantee.
ii) CO: 0.083 lb/MMBTU, AP-42(7/98), Table 1.4-1.
iii) PM-2.5: 0.0075 lb/MMBTU, AP-42(7/98), Table 1.4-2.
iv) SO_2: 26.93 lb/MMSCF, NSPS, based on the Subpart Ja emission standard for H_2S concentration in refinery gas (162 ppmv based on a three-hour average and 60 ppmv annual average) and 100% H_2S to SO_2 conversion.
v) VOC: 0.0054 lb/MMBTU, AP-42(7/98), Table 1.4-2.
vi) CO_2e: based on a refinery fuel gas analysis and factors from 40 CFR Part 98, Subpart C, Table C-2 for Petroleum fuel.

Criteria Pollutant Emissions and GHG Emissions from EUG 13B

	NO_X [1]		CO [2]		$PM_{2.5}$ [3]		SO_2 [2]		VOC [2]		CO_2e [2]
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**TPY**
B-15001	12.84	35.01	12.84	56.23	2.36	6.44	8.37	13.59	1.71	7.49	163,795

1) Maximum potential NO_X emissions (annual basis) were calculated using a NO_X emission factor of 0.045 lb/MMBtu for the ultra low-NO_X burners and an annual average firing rate of 177.63 MMBtu/hr. Potential NO_X emissions are limited by a specific condition, requiring that the unit be equipped with a continuous emissions monitoring system (CEMS) and that NO_X emissions be calculated every month and limited to 35.01 TPY (12-month rolling total). Hourly NO_X emissions were calculated using the 0.045 lb/MMBtu NO_X emissions rate and the unit's maximum firing capacity, 285.3 MMBtu/hr.
2) Potential emissions for other pollutants were estimated using the maximum firing capacity of the unit (285.3 MMBtu/hr), a typical fuel heat rate (918 Btu/scf HHV), and continuous firing (8,760 hours/year).
   a. CO: 0.045 lb/MMBtu (vendor guarantees).
   b. VOC: 5.5 lb/MMscf [AP-42(7/98), Table 1.4-2].
   c. SO_2: Annual emissions were calculated using 9.98 lb/MMscf (derived from NSPS, Subpart Ja emission standards for H_2S in refinery fuel gas – 60 ppmv annual average and a 100% conversion of H_2S to SO_2). Hourly emissions for SO_2 are based on an hourly emission rate of 26.93 lb/MMscf which was derived from the three-hour maximum allowable H_2S concentration set by NSPS, Subpart Ja: 162 ppmv.
   d. Greenhouse gas (GHG) emissions were calculated using the natural gas emission factors [from AP-42(7/98), Table 1.4-2] for CO_2 (120,000 lb/MMscf), CH_4 (5.5 lb/MMscf), and N_2O (0.64 lb/MMscf) with the global warming potential for CH_4 (25) and N_2O (298) used to calculate CO_2e.
3) Maximum potential emissions for $PM_{10}/PM_{2.5}$ (annual basis) were calculated using a $PM_{10}/PM_{2.5}$ emissions rate of 7.6 lb/MMscf [AP-42(7/98), Table 1.4-2], an annual average firing rate of 177.63 MMBtu/hr, and a typical fuel heat rate (918 Btu/scf HHV). Hourly $PM_{10}/PM_{2.5}$ emissions were calculated using the maximum heat input rate (285.3 MMBtu/hr).

Criteria Pollutant Emissions from EUG 14

	NO_X		CO		PM_{10}		SO_2		VOC	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
HI-81001	19.55	8.56	106.37	46.59	2.14	0.94	9.66	4.23	40.25	17.63
HI-81002	28.16	11.04	153.23	60.09	3.93	1.54	13.91	5.46	57.98	22.74
HI-81003	18.57	8.13	101.03	44.25	2.03	0.89	9.17	4.02	38.23	16.74
Totals	**66.28**	**27.73**	**360.63**	**150.93**	**8.10**	**3.37**	**32.74**	**13.71**	**136.46**	**57.11**

TPY emissions, from flares HI-81001, HI-81002, HI-81003, are based on heat ratings of 28.7, 37.08, and 27.3 MMBTUH, respectively and the following:

NO_X, CO, & VOC – AP-42 (1/95), Section 13.5;

PM_{10} – AP-42 (7/98), Section 1.4; and

SO_2 - A fuel-gas H_2S concentration of 0.1 grain/DSCF and a HHV of 800 BTU/SCF (0.0336 lb/MMBTU).

Short-term emission (lb/hr) are based on the systems design and steam availability of ten times the heat ratings for HI-81001 and HI-8003, and a short-term heat rate maximum of 414.13 MMBTUH for HI-81002.

GHG Emissions from EUG 14

	CO_2		N_2O (CO_{2e})		CH_4 (CO_{2e})		CO_{2e}	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
HI-81001	40,153	17,587	19	8	105	46	42,101	17,641
HI-81002	62,202	24,394	27	11	41	16	62,271	24,421
HI-81003	38,938	17,055	18	8	59	26	39,015	17,089
Totals	**141,293**	**59,036**	**64**	**27**	**205**	**88**	**148,387**	**59,151**

TPY emissions, from flares HI-81001, HI-81002, HI-81003, are based on heat ratings of 28.7, 37.08, and 27.3 MMBTUH, respectively and the following:

A worst case heat content, composition, and 98% destruction efficiency to give a CO_2 emission factor of ~ 142.76, 150.2, 145.54 lb/MMBTU, respectively based on the composition of different streams routed to the flares over the last nine years.

The default N_2O emission factor for natural gas from Table C-2 to Subpart C of 40 CFR Part 98.

A 98% destruction efficiency of the CH_4 4.83%, 1.08, 2.67%, respectively in the streams with the worst case emissions routed to the flares over the last nine years which resulted in an emission factor of ~ 0.0146, 0.00398, 0.00869 lb/MMBTU.

Short-term emission (lb/hr) are based on the systems design and steam availability of ten times the heat ratings for HI-81001 and HI-8003, and a short-term heat rate maximum of 414.13 MMBTUH for HI-81002.

Criteria Pollutant Emissions from EUG 15 & 23

	NO_X		CO		PM_{10}		SO_2		VOC	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
HI-501	1.94	8.50	1.09	4.76	0.43	1.88	11.98	52.47	0.07	0.31
HI-5602	3.96	17.35	3.33	14.57	0.30	1.32	26.2	114.7	0.20	1.00
Totals	**5.90**	**25.85**	**4.42**	**19.33**	**0.73**	**3.20**	**38.18**	**167.2**	**0.27**	**1.31**

Emissions from HI-501 are based on combustion of 8.2 MMBTUH of auxiliary fuel, combustion of 217,512 SCFH of waste gas with a heat content of 23 BTU/SCF, and the following:

NO_X, CO, PM10, VOC - AP-42 (7/98), Section 1.4; NO_X emissions include a safety factor of 1.5 and PM_{10} emissions have been adjusted for emissions of H_2SO_4; and

SO_2 - NSPS, Subpart J, SO_2 emission limit of 250 ppmdv and a flow rate of 288,212 DSCFH @ 0% O_2; approximately 1.8% of SO_2 emissions will be emitted as SO_3 and converted to H_2SO_4.

The emissions from the # 1 sulfur pit (EU SSP520) are vented to HI-501.

Emissions from HI-5602 are based on combustion of 27.7 MMBTUH of auxiliary fuel, combustion of 552,396 SCFH of waste gas with a heat content of 23 BTU/SCF, and the following:

NO_X, CO, PM10, VOC - AP-42 (7/98), Section 1.4; and

SO_2 - NSPS, Subpart J, SO_2 emission limit of 250 ppmdv and a flow rate of 630,000 DSCFH @ 0% O_2; approximately 1.8% of SO_2 emissions will be emitted as SO_3 and converted to H_2SO_4.

The emissions from the # 2 sulfur storage tank (TK-5602) are vented to this control device.

GHG Emissions from EUG 15 & 23

	CO_2		N_2O (CO_{2e})		CH_4 (CO_{2e})		CO_{2e}	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
HI-501	4,823	16,899	----	----	----	----	4,823	16,899
HI-5602	6,175	21,639	----	----	----	----	6,175	21,639
Totals	**10,998**	**38,538**	**0**	**0**	**0**	**0**	**10,998**	**38,538**

The CO_2 emissions from HI-501 and H-5602 are based on equation Y-12 from § 98.253(f)(4), a volumetric flow rate of sour gas feed (including sour water stripper gas) to the sulfur recovery plants of 166,379 and 213,040 SCFY, respectively, and the default mole fraction of carbon in the sour gas of 20%. Short term emission rates are based on the annual emissions divided over 8,760 hours a year and a 25% safety factor.

The CH_4 and N_2O emissions are not required to be calculated for sulfur recovery plants.

Criteria Pollutant Emissions from EUG 16

	NO_X		CO		PM_{10}		SO_2		VOC	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
HI-801	9.37	41.05	6.67	22.47	1.14	3.84	8.00	35.03	0.44	1.47

Potential emissions from the Asphalt Blowstill are based on the following:

NO_X - For emissions from combustion of the auxiliary fuel, emissions were based on a heat rating of 12 MMBTUH and the emission factor from AP-42 (7/98), Section 1.4 multiplied by 1.5; for emissions from combustion of the waste gas, emissions were based on a flow rate of 21,287 lb/hr of waste gas, a heat content of 2,363 BTU/lb, and the emission factor from AP-42 (7/98), Section 1.4 multiplied by 1.5; for emissions from nitrogen in the waste gas (as NO_2), emissions were based on a concentration of 6.2 ppmdv and a flow rate of 282,823 SCFH; Short term emission rates (lb/hr) were then increased by a 30% safety factor;

CO & VOC, & PM_{10} - For emissions from combustion of the auxiliary fuel, emissions were based on a heat rating of 12 MMBTUH and AP-42 (7/98), Section 1.4; for emissions from combustion of the waste gas, emissions were based on a flow rate of 21,287 lb/hr of waste gas, a heat rating of 2,363 BTU/lb, and AP-42 (7/98), Section 1.4; emissions of PM_{10} have been adjusted for emissions of H_2SO_4; Short term emission rates (lb/hr) were then increased by a 30% safety factor; and

SO_2 - A refinery fuel-gas H_2S concentration of 0.1 grain/DSCF, a flow rate of 0.016 MMSCFH of auxiliary fuel, and a flow rate of 0.283 MMSCFH of waste gas; approximately 1.8% of SO_2 emissions will be emitted as SO_3 and converted to H_2SO_4.

GHG Emissions from EUG 16

	CO_2		N_2O (CO_{2e})		CH_4 (CO_{2e})		CO_{2e}	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
HI-801	13,616	47,709	----	----	400	1,400	14,016	49,109

The CO_2 emissions from HI-801 are based on equation Y-16a from § 98.253(h)(2), a throughput of 4,380 MBY of asphalt, and the default emission factor of 2,750 metric tons of carbon per million barrels of asphalt.

The CH_4 emissions from HI-801 are based on equation Y-17 from § 98.253(h)(2), a throughput of 4,380 MBY of asphalt, and the default emission factor of 580 metric tons of methane per million barrels of asphalt.

Short term emission rates are based on the annual emissions divided over 8,760 hours a year and a 25% safety factor.

The N_2O emissions are not required to be calculated for asphalt blowstills.

Criteria Pollutant Emissions from the EUG 17

	NO_X		CO		PM_{10}		SO_2		VOC	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
HI-13001	5.20	15.79	13.00	39.48	0.00	0.00	0.01	0.01	30.16	73.66

Emissions from loading are based on a throughput of 22,525,714 bbl/yr and 155,782 gal/hr.

VOC emissions from the vapor combustor are based on a limit of 10 mg VOC/L gasoline loaded

Annual VOC emissions from fugitive loading losses are based on AP-42 (1/95), Section 5.2, a saturation factor of 1.0, a vapor pressure (vp) of 5.8 psia, a temperature of 60 ºF, a vapor molecular weight of 65, and a 99.2% collection efficiency.

Hourly VOC emissions from fugitive loading losses are based on AP-42 (1/95), Section 5.2, a saturation factor of 1.0, a maximum vp of 9.4 psia, a maximum temperature of 93 ºF, a vapor molecular weight of 65, and a 99.2% collection efficiency.

NO_X, CO, and SO_2 emissions from the vapor combustor are based on the following emission factors:

NO_X - 4 mg/L of gasoline loaded (0.03338 lb/Mgal);

CO - 10 mg/L of gasoline loaded (0.08345 lb/Mgal); and

SO_2 - Combustion of 2,000 gallons of distillate fuel oil and a factor of 7.1 lb/Mgal.

The emissions factors for diesel are based on multiplying the gasoline emission factors by the ratio of the calculated loading losses using AP-42 (1/95), Section 5.2 for diesel and gasoline.

Loading losses for diesel are based on AP-42 (1/95), Section 5.2, a saturation factor of 0.6, a bulk liquid temperature of 60 ºF, a vapor pressure of 0.0236 psia, and a vapor molecular weight of 130.

GHG Emissions from EUG 17

	CO_2		N_2O (CO_{2e})		CH_4 (CO_{2e})		CO_{2e}	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
HI-13001	6,648	13,295	17	34	7	14	6,672	13,343

Emissions loading are based on a throughput of 22,525,714 bbl/yr and 155,782 gal/hr.

Annual emissions are from loading losses are based on AP-42 (1/95), Section 5.2, a saturation factor of 1.0, a vapor pressure (vp) of 5.8 psia, a temperature of 60 ºF, a vapor molecular weight of 65, and a 99.2% collection efficiency.

Hourly emissions from loading losses are based on AP-42 (1/95), Section 5.2, a saturation factor of 1.0, a maximum vp of 9.4 psia, a maximum temperature of 93 ºF, a vapor molecular weight of 65, and a 99.2% collection efficiency.

Emissions are based on combustion of gasoline calculated using the loading loss calculations, a density of 6.17 lb/gal, the default heat content for motor gasoline from Table C-1 to Subpart C of 40 CFR Part 98, and the following emission factors:

The default CO_2 emission factor for motor gasoline from Table C-1 to Subpart C of 40 CFR Part 98.

The default N_2O and CH_4 emission factors for petroleum from Table C-2 to Subpart C of 40 CFR Part 98.

Criteria Pollutant Emissions from the FCCU (EUG 18)

	TPY NO_X	TPY CO	TPY PM_{10}	TPY SO_2
BACT/SEP Emission Limits	307.0	182.7	46.6	202.4

Emission limits for the FCCU are based on the following [established as BACT in Permit No. 98-172-C (M-20) PSD]:

NO_X Emissions:

NO_X emissions from the FCCU No. 1 Regenerator were based on a 35% reduction of stack test results (65.34 lb/hr) conducted on January 22-23, 1998, and extrapolated from a feedstock rate of 25,836 bbl/day to 30,000 bbl/day. NO_X emissions from the FCCU No. 2 Regenerator were based on stack test results (27.69 lb/hr) conducted on January 22-23, 1998, and extrapolated from a feedstock rate of 25,836 bbl/day to 30,000 bbl/day.

SEP emissions reductions are based on an additional 15% reduction of the FCCU No. 1 NO_X emissions the FCCU No. 2 Regenerator remained the same.

CO Emissions:

CO emissions from the FCCU No. 1 Regenerator were based on a flow rate of 46,018 SCFM and a concentration of 175 ppmdv @ 0% O_2. CO emissions from the FCCU No. 2 Regenerator were based on 30,221 SCFM and a concentration of 50 ppmdv @ 0% O_2.

PM_{10} Emissions:

PM_{10} emissions from the FCCU No. 1 and No. 2 Regenerators were based on a 90% reduction of (front-half) the following: FCCU No. 1 Regenerator stack test results (52.56 lb/hr) conducted on August 12 1999, and extrapolated from a feedstock rate of 26,322 bbl/day to 30,000 bbl/day; PM_{10} emissions from the FCCU No. 2 Regenerator were based on stack test results (40.87 lb/hr) conducted on August 12, 1999, and extrapolated from a feedstock rate of 26,322 bbl/day to 30,000 bbl/day.

SO_2 Emissions:

SO_2 emissions from the FCCU No. 1 and No. 2 Regenerators were based on a 90% reduction of the following: FCCU No. 1 Regenerator emission estimates based on stack test results (246.18 lb/hr) conducted on January 22-23, 1998, and extrapolated from a feedstock rate of 25,836 bbl/day and a feedstock sulfur content of 0.2733% by weight to 30,000 bbl/day and a feedstock sulfur content of 0.3% by weight; and FCCU No. 2 Regenerator emissions estimates based on stack test results (112.35 lb/hr), which was conducted on August 12, 1999, extrapolated from a feedstock rate of 26,322 bbl/day and a feedstock sulfur content of 0.2587% by weight to 30,000 bbl/day and a feedstock sulfur content of 0.3% by weight.

The hydrogen cyanide (HCN) emission limit for the FCCU shown was established to recognize that HCN is released from the FCCU during normal operation of the FCCU. The emissions were based on stack testing conducted on March 27, 2012, and March 28, 2012, and were then factored up to potential emissions based on the nitrogen feed rate and coke burn rate.

FCCU HCN Emissions

	lb/hr
Average Hourly Emissions During Test (lb/hr)	1.26
Average FCCU Feed Nitrogen Content During Test (ppmw)	1,039
Average Coke Burn Rate During Test (TPH)	11.17
Maximum FCCU Feed Nitrogen Content (ppmw)	3,350
Maximum Coke Burn Rate (TPH)	12.50
Potential HCN Emissions (lb/hr)	4.55
Potential HCN Emissions (TPY)	20.00

GHG Emissions from EUG 18

	CO_2		N_2O (CO_{2e})		CH_4 (CO_{2e})		CO_{2e}	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
FGS-200 (Coke Burn)	143,551	503,002	695	2,436	385	1,351	144,631	506,789
FGS-200 (Fuel Gas)	33,539	117,520	20	72	7	24	33,566	117,616
Totals	**177,090**	**620,522**	**715**	**2,508**	**392**	**1,375**	**178,197**	**624,405**

The CO_2 emissions from FGS-200 coke burn off are based on continuous emission monitoring data. The CO_2 emission data was plotted versus the coke burn rate. The maximum CO_2 emission rate was based on two standard deviations from a linear regression analysis of the data and then adjusted up to the maximum throughput of the FCCU (30 MBPD).

The CH_4 emissions from coke burn off are based on equation Y-9 from § 98.253(c)(4) which is a ratio of the emission factors for CH_4 (Petroleum) and CO_2 (Petroleum coke).

The N_2O emissions from coke burn off are based on equation Y-10 from § 98.253(c)(5) which is a ratio of the emission factors for N_2O (Petroleum) and CO_2 (Petroleum coke).

Emissions from combustion of refinery fuel gas in the CO Boilers during normal operation of the FCCU are based on a heat input rating of 249 MMBTUH (HHV) and the following emission factors:

The refinery fuel gas maximum CO_2 emission factor of 110.3 lb/MMBTU based on the composition of the refinery fuel gas over the last nine years.

The default N_2O emission factor for natural gas from Table C-2 to Subpart C of Part 98.

The default CH_4 emission factor for natural gas from Table C-2 to Subpart C of Part 98 times the maximum percent CH_4 in the refinery fuel gas over the last nine years.

Short term emission rates are based on the annual emissions divided over 8,760 hours a year and a 25% safety factor.

Criteria Pollutant Emissions from EUG 19

EU B-253A is included in the emissions from FGS-200 (EUG 18). The primary operating scenario is firing 100% refinery fuel-gas. The secondary operating scenario is firing all of the FCCU No. 1 Regenerator flue-gas in combination with refinery fuel-gas. The emissions shown below only represent the emissions arising from operation of the boiler itself and not the criteria pollutant emissions processed through the boiler.

Criteria Pollutant Emissions from EUG 19

	NO_X		CO		PM_{10}		SO_2		VOC	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
B-253B	8.64	37.84	11.86	51.94	1.07	4.70	4.84	21.19	0.78	3.40

Emissions are based on a heat input rating of 144 MMBTUH and the following:

NO_X - manufacturers guarantee of 0.06 lb/MMBTU;

CO, VOC, & PM_{10} - AP-42 (7/98), Section 1.4; and

SO_2 - A fuel-gas H_2S concentration of 0.1 grain/DSCF and a HHV of 800 BTU/SCF (0.0336 lb/MMBTU).

GHG Emissions from EUG 19

	CO_2		N_2O (CO_{2e})		CH_4 (CO_{2e})		CO_{2e}	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
B-253A	15,878	69,546	9	41	3	14	15,890	69,601
B-253B	15,878	69,546	9	41	3	14	15,890	69,601
Totals	**31,756**	**139,092**	**18**	**82**	**6**	**28**	**31,780**	**139,202**

Emissions are based on the heat input ratings HHV (MMBTUH) and the following emission factors:

The refinery fuel gas maximum CO_2 emission factor of 110.3 lb/MMBTU based on the composition of the refinery fuel gas over the last nine years.

The default N_2O emission factor for natural gas from Table C-2 to Subpart C of Part 98.

The default CH_4 emission factor for natural gas from Table C-2 to Subpart C of Part 98 times the maximum percent CH_4 in the refinery fuel gas over the last nine years.

PM Emissions from EUG 25

	PM_{10}	
EU	**lb/hr**	**TPY**
Cat_Hop	0.46	2.01

Potential emissions from the catalyst hoppers are based on the flow rate and factors for spent and fresh catalyst. Emissions due to spent catalyst are based on a continuous catalyst recirculation rate of approximately 1,050 Tons/hr through two hoppers and an emission factor of 0.01 lbs PM/ton (AP-42 (1/95), Section 11.24, Table 11.24.2, high moisture ore, material handling and transfer - all minerals except bauxite); and emissions due to fresh catalyst are based on a continuous catalyst recirculation rate of 13 tons/hr, an emission factor of 0.12 lbs PM/ton (AP-42 (1/95), Section 11.24, Table 11.24.2, low moisture ore, material handling and transfer - all minerals except bauxite), and continuous operation. PM_{10} emissions for the high moisture ore are 40% of PM emissions. PM_{10} emissions for the low moisture ore are 50% of PM emissions. The high moisture ore factor was utilized for the spent catalyst since live steam is injected to control emissions of PM. The emissions from the catalyst hoppers are vented to a cyclone with an efficiency of 70% for PM and 50% for PM_{10}. The cyclones are vented to the FCCU wet scrubber with an efficiency of 93.3% for PM and 90% for PM_{10}.

Total Allowable Criteria Pollutant Emissions from EUG 18, 19, & 25

NO_X		CO		PM_{10}		SO_2		VOC	
lb/hr	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
118.0	344.8	178.1	234.7	22.83	53.35	66.44	223.6	0.78	3.40

Allowable emissions are the combination of the BACT allowables plus the new Boiler/CO Boiler allowables plus the catalyst hopper allowables.

Criteria Pollutant Emissions from EUG 20

	NO_X		CO		PM_{10}		SO_2		VOC	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
EEQ-8801	24.14	6.04	5.53	1.38	0.70	0.18	0.01	<0.01	0.65	0.16
P1806	9.80	2.45	6.79	1.70	0.03	0.01	0.02	0.01	0.92	0.23
P1807A	19.20	0.56	4.40	0.13	0.56	0.02	0.01	<0.01	0.51	0.02
P1807B	19.20	0.56	4.40	0.13	0.56	0.02	0.01	<0.01	0.51	0.02
P1807C	19.20	0.56	4.40	0.13	0.56	0.02	<0.01	<0.01	0.51	0.02
EG1880-01	2.54	0.63	98.12	24.53	0.01	<0.01	0.01	<0.01	0.03	0.01
EG1880-02	0.89	0.22	0.77	0.19	0.04	0.01	<0.01	<0.01	0.33	0.08
EG-ADMIN	3.52	0.88	3.09	0.77	0.18	0.04	<0.01	<0.01	1.35	0.34
Totals	**98.49**	**11.9**	**127.47**	**28.96**	**2.64**	**0.31**	**0.08**	**0.07**	**4.81**	**0.88**

Emissions from the emergency **diesel-fired** engines are based on operating 500 hours a year (except for P1807A, P1807B, & P1807C which are based on 58 hours), the listed ratings, and the following emission factors:

EEQ-8801, P1807A, P1807B, and P1807C: NO_X, CO, & PM_{10}, VOC – AP-42 (10/96), Section 3.3 or 3.4, as applicable; SO_2 – AP-42 (10/96), Section 3.4, and a fuel sulfur concentration of 15 ppmw.

EG1880-02: the applicable Tier III emission levels indicated below. Emissions of NO_X+HC are assumed to be NO_X. VOC emissions are estimated based on AP-42 (10/96), Section 3.3. SO_2 emissions are based on a fuel sulfur concentration of 15 ppmw.

Note: due to rounding, the totals do not necessarily add up exactly to the values shown in the table, especially when the values shown for an individual EU are less than 0.01.

40 CFR Part 89, Non-Road CI-RICE Emission Standards, g/kW-hr (g/hp-hr)

Tier	kW	Model Years	NO_X+HC	CO	PM
III	75 ≥ kW < 130	2007-2013	4.0 (3.0)	5.0 (3.7)	0.30 (0.22)

Emissions from the emergency **gas-fired** engines are based on operating 500 hours a year, the listed ratings, and the following emission factors:

P1806: NO_X: 11.7 g/hp-hr; CO: 8.1 g/hp-hr; PM_{10}: 0.03 g/hp-hr; VOC: 1.1 g/hp-hr; SO_2 - based on 3 ppmvd H_2S, 1,020 BTU/SCF (HHV - 0.0005 lb/MMBTU), and a heat input of 7,000 BTU/hp-hr.

EG1880-01: the applicable NSPS, Subpart JJJJ emission levels indicated below. Emissions of NO_X+HC are assumed to be NO_X. PM_{10} and VOC emissions are estimated based on AP-42 (8/00), Section 3.2. SO_2 - based on 3 ppmvd H_2S, 1,020 BTU/SCF (HHV - 0.0005 lb/MMBTU).

Emission Standards from Table 1, Subpart JJJJ, g/hp-hr

Engine Type & Fuel	Max Power (hp)	NO_X	CO
Emergency	25 < hp < 130	10	387

GHG Emissions from EUG 20

	CO_2		N_2O (CO_{2e})		CH_4 (CO_{2e})		CO_{2e}	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
EEQ-8801	1,148	287	3	1	1	0	1,152	288
P1806	333	83	1	0	0	0	334	83
P1807A	913	26	2	0	1	0	916	26
P1807B	913	26	2	0	1	0	916	26
P1807C	913	26	2	0	1	0	916	26
EG1880-01	101	25	0	0	0	0	101	25
EG1880-02	153	38	0	0	0	0	153	38
EG-ADMIN	630	158	0	0	0	0	632	158
Totals	**5,104**	**669**	**10**	**1**	**4**	**0**	**5,120**	**670**

Emissions from the emergency engines are based on operating 500 hours a year (except for P1807A, Pa807B, & P1807C which are based on 58 hours), the listed ratings, a heat input of 7,000 BTU/hp-hr for the diesel-fired engines and 7,500 BTU/hp-hr for the natural gas-fired engines, and the following emission factors:

The default CO_2 emission factors for diesel and natural gas from Table C-1 to Subpart C of Part 98.

The default N_2O and CH_4 emission factors for petroleum and natural gas from Table C-2 to Subpart C of Part 98.

Emissions from EUG 21

HI-81004 operates in lieu of HI-81001 and therefore does not increase the emissions totals.

Criteria Pollutant Emissions from EUG 22

	NO_X		CO		PM_{10}		SO_2		VOC	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
C-80018	15.50	31.00	3.34	6.68	1.10	2.20	0.01	0.01	1.24	2.47

Emissions from the diesel fired engine are based on 4,000 operating hours a year, 500-hp, and the following emission factors:

NO_X, CO, & PM_{10}, VOC - AP-42 (10/96), Section 3.3, and

SO_2 - AP-42 (10/96), Section 3.4, and a maximum sulfur content of 15 ppmw.

GHG Emissions from EUG 22

	CO_2		N_2O (CO_{2e})		CH_4 (CO_{2e})		CO_{2e}	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
C-80018	571	1,141	1	3	1	1	573	1,145

Emissions from the diesel fired engine are based on 4,000 operating hours a year, 500-hp, a heat input of 7,000 BTU/hp-hr, and the following emission factors:

The default CO_2 emission factor for diesel from Table C-1 to Subpart C of Part 98.

The default N_2O and CH_4 emission factor for petroleum from Table C-2 to Subpart C of Part 98.

Criteria Pollutant Emissions from EUG 24

	NO_X		CO		PM_{10}		SO_2		VOC	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
CCR	1.19	5.21	0.44	1.93	0.56	2.46	0.67	2.91	0.05	0.20

Emissions are based on a coke-burning rate of 70 lbs/hr, which is equivalent to a maximum catalyst recirculation rate of 1,000 lb/hr and a coke generation rate of 7% of the catalyst weight, with a coke maximum sulfur content of 0.5% by weight. Coke combustion emissions were based on AP-42 (1/95), Section 1.1, for sub-bituminous coal combustion. PM_{10} emissions also include a recovery factor for the catalyst of 99.99%.

NO_X - 34 lb/ton of coke combusted (Pulverized coal fired, wet bottom);
CO - a concentration of 500 ppmv @ 0% O_2 and a flow rate of 200 DSCFM;
PM_{10} - 13.2 lb/ton of coke combusted (Spreader Stoker); 0.46 lb/hr combustion & 0.10 lb/hr catalyst;
SO_2 - 38 x (Sulfur Content) lb/ton of coke combusted (Spreader Stoker); and
VOC - 1.3 lb/ton of coke combusted (Underfeed Stoker).

GHG Emissions from EUG 24

	CO_2		N_2O (CO_{2e})		CH_4 (CO_{2e})		CO_{2e}	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
CCR	301	1,057	1	2	0	1	302	1,060

The CO_2 emissions from CCR coke burn off are based on equation Y-11 from § 98.253(e)(3), a carbon content of the coke of 94%, a coke burn off quantity of 11.5 kg/cycle, and 24,172 regenerations per year.

The CH_4 emissions from coke burn off are based on equation Y-9 from § 98.253(c)(4) which is a ratio of the emission factors for CH_4 (Petroleum) and CO_2 (Petroleum coke).

The N_2O emissions from coke burn off are based on equation Y-10 from § 98.253(c)(5) which is a ratio of the emission factors for N_2O (Petroleum) and CO_2 (Petroleum coke).

Short term emission rates are based on the annual emissions divided over 8,760 hours a year and a 25% safety factor.

HCl Emissions from EUG 24

	Uncontrolled		Controlled	
	lb/hr	**TPY**	**lb/hr**	**TPY**
HCl Emissions	10.10	44.23	0.30	1.33

Ethylene dichloride ($C_2H_4Cl_2$) or perchloroethylene ($Cl_2C{:}CCl_2$) is injected into the reformer and then discharged as hydrogen chloride (HCl). The facility is required to comply with the MACT (97% control of HCl from the CCR or 10 ppmv HCl @ 3% O_2). Ethylene dichloride or perchloroethylene is almost completely destroyed by reaction with the catalyst and air. Estimated material usage is based on 0.0106 lb of perchloroethylene per barrel with the CCR running at 26 MBPD. Potential HCl emissions are based on 100% of the chloride being converted to HCl and being emitted from the CCR. Emissions of HCl from the CCR after control are estimated using the required control efficiency of 97%. The controls for HCl will also help reduce PM_{10} emissions by approximately 95%.

Criteria Pollutant Emissions from EUG 26 Control of the WWTP Bioreactor Waste Gases

Actual Emissions	TPY NO_X	TPY CO	TPY PM_{10}	TPY SO_2	TPY VOC
Operating Scenario 1 - RTO (HI-8801)					
Incinerator-Fuel Gas[1]	7.88	5.41	0.49	2.20	0.35
Incinerator-Waste Gas[2]	18.78	0.07	<0.01	14.12	1.87
Operating Scenario 2 – Atmospheric Venting (ATMV-8801)					
Bioreactor-Waste Gas[3]	----	----	----	----	33.00
Totals	26.66	5.48	0.50	16.32	33.00

1 Potential emissions from combustion of auxiliary refinery fuel gas are based on the following:
NO_X - Burner emission factor of 0.12 lb/MMBTUH @ 15 MMBTUH;
CO, PM_{10}, & VOC - AP-42 (7/98), Section 1.4 @ 15 MMBTUH; and
SO_2 - A fuel-gas H_2S concentration of 0.1 grain/DSCF @ 15 MMBTUH & 800 BTU/SCF.

2 Potential emissions from combustion of the bioreactor off-gases are based on a flow rate of approximately 120,000 SCFH and the following:
NO_X - a maximum concentration of 315 ppmv NH_3 in the bioreactor off-gases and 95.0% combustion efficiency;
CO & PM_{10} - a heat input of 0.2 MMBTUH, and AP-42, Section 1.4 (7/98);
SO_2 - a maximum concentration of 0.1 grain/DSCF H_2S in the bioreactor off-gases and 100.0% combustion efficiency; and
VOC - a waste gas flow rate of 8.52 lb VOC/hr and a combustion efficiency of 95%.

3 Uncontrolled emissions are based on a waste gas flow rate of 120,000 SCFH, a maximum VOC concentration of 622 ppmv as propane, and venting to the atmosphere for 7,746 hours/yr.

GHG Emissions from EUG 26

	CO_2		N_2O (CO_{2e})		CH_4 (CO_{2e})		CO_{2e}	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
Operating Scenario 1 - RTO (HI-8801)								
Incinerator-Fuel Gas[1]	1,654	7,244	1	4	0	1	1,655	7,249
Incinerator-Waste Gas[2]	11,585	50,743	42	183	18	78	11,645	51,004
Operating Scenario 2 – Atmospheric Venting (ATMV-8801)								
Waste Gas[3]	2,783	12,191	----	----	25,361	111,080	28,144	123,271
Totals	**13,239**	**57,987**	**43**	**187**	**25,361**	**111,080**	**28,144**	**123,271**

1 - Emissions from combustion of refinery fuel gas are based on a heat input of 15 MMBTUH (HHV) and the following emission factors:
The refinery fuel gas maximum CO_2 emission factor of 110.3 lb/MMBTU based on the composition of the refinery fuel gas over the last nine years.
The default N_2O emission factor for natural gas from Table C-2 to Subpart C of Part 98.
The default CH_4 emission factor for natural gas from Table C-2 to Subpart C of Part 98 times the maximum percent CH_4 in the refinery fuel gas over the last nine years.

2 - Emissions from combustion of waste gas from the WWTP are based on a waste gas flow rate of 120,000 SCFH, the default heat content of biogas, and the following emission factors:
The default CO_2 emission factor for biogas from Table C-1 to Subpart C of Part 98.
The default N_2O and CH_4 emission factors for biogas from Table C-2 to Subpart C of 40 CFR Part 98.

3 - Emissions from the waste gas from the WWTP are based on a waste gas flow rate of 120,000 SCFH, and a CO_2 and CH_4 content of 50% each.

Criteria Pollutant Emissions from EUG 27

	NO_X		CO		PM_{10}		SO_2		VOC	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
RCALOAD 900	0.10	0.12	0.54	0.63	0.01	0.01	----	----	1.10	1.29

Potential emissions are based on a short-term throughput of 220 gallons per minute, an annual throughput of 733,505 bbl/yr, and the following:

NO_X & CO - the emission factors from AP-42 (1/95), Section 13.5, and a heat rating of 130,000 BTU/gallon;

VOC - the allowable emission factor from NESHAP, Subpart R of 10 mg/L (0.0835 lb/1,000 gallon).

The railcar loading station will be vented through the asphalt blowstill and will be added to the emission limits for the asphalt blowstill thermal oxidizer.

GHG Emissions from EUG 27

	CO_2		N_2O (CO_{2e})		CH_4 (CO_{2e})		CO_{2e}	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
RCALOAD 900	3	0	0	0	0	0	3	0

Emissions from combustion of waste gas from the loading operations are based on a throughput of 220 gallons per minute, an annual throughput of 733,505 bbl/yr, the allowable emission factor from NESHAP, Subpart R of 10 mg/L (0.0835 lb/1,000 gallon), combustion of gasoline with a density of 6.17 lb/gal, the default heat content for motor gasoline from Table C-1 to Subpart C of 40 CFR Part 98, and the following emission factors:

The default CO_2 emission factor for motor gasoline from Table C-1 to Subpart C of 40 CFR Part 98.

The default N_2O and CH_4 emission factors for petroleum from Table C-2 to Subpart C of 40 CFR Part 98.

The railcar loading station will be vented through the asphalt blowstill and will be added to the emission limits for the asphalt blowstill thermal oxidizer.

VOC Emissions from EUG 28

		Emissions
EU	**Disconnects**	**TPY**
EtOHTT	10,000	0.018
EtOHRC	4,300	0.008
BDTT	630	0.920
Total		**0.946**

Tank Truck/Railcar ethanol and toluene unloading emissions are based on the installation of loading arms equipped with dry-disconnect couplings performing at a 2 cm^3 release per loading disconnect (0.0038 lb/disconnect).

Potential emissions from biodiesel unloading from the transfer hose are based on emissions of 0.07 lb/disconnect. Potential emissions from biodiesel unloading from the drip pan are based on a drip pan area of 0.743 m^2, a wind speed of 3.6 m/s, a MW of 180 g/g-mol, a vapor pressure of 0.055 kPa, a temperature of 290 K, and Equation 8.4-22 from the Emission Inventory Improvement Program: Volume II (2/2005), Chapter 8, Section 4:

$$E_{lb/hr} = \frac{0.00438 \ x \ U^{0.78} \ x \ (18)^{1/3} \ x \ MW^{2/3} \ x \ Area \ x \ TVP \ x \ 3600}{R \ x \ Temp}$$

VOC Emissions from EUG 29

EU	Emissions lb/disconnect	Throughput BPY	Emissions TPY
LPG-RC-UNLOAD[1]	3.49	680,980	1.51
LPG-TT-UNLOAD[1]	3.49	643,130	5.89
LPG-RC-LOAD[1]	3.49	1,902,964	4.23
LPG-TT-LOAD[1]	3.74	621,413	6.10
C_3[2]	15.57	689,631	28.19
Total			**45.92**

[1] - based on mean product density 4.67 lb/gallon and a disconnect factor of 0.10 ft^3.
[2] - based on mean product density 4.92 lb/gallon and a disconnect factor of 0.423 ft^3.

VOC Emissions from EUG 30

Loading Station (EU)	Throughput BPY	Emissions TPY
Railcar (ASPHALT-RC-LOAD) Tank Truck (ASPHALT-TT-LOAD)	4,745,000	16.69

The emissions are based on AP-42 (1/95), Section 5.2 and the listed throughputs.

Equipment Leak VOC Emissions from EUG 31/32/33/34

Number Items	Type of Equipment	Factor (kg/hr/source)	Emissions (TPY)
18,289	Gas/ Light-Liquid Valves[1]	0.00221	390.29
3,433	Gas/ Light-Liquid Valves[2]	0.00024	7.96
292	Pressure Relief Valves[3]	0.00320	9.02
26	Pressure Relief Valves[4]	0.00309	0.78
58,248	Gas/Light-Liquid Flanges	0.00025	140.61
11	Compressor Seals[3]	0.01272	1.35
213	Light-Liquid Pump Seals[5]	0.00519	10.67
466	Other	0.00865	38.92
8,281	Heavy-Liquid Valves	0.00023	19.54
18,419	Heavy-Liquid Flanges	0.00025	48.43
148	Heavy-Liquid Pump Seals	0.02100	30.01
Total			**697.58**

Fugitive VOC emissions are based on the factors below derived from EPA's *1995 Protocol for Equipment Leak Emission Estimates* (EPA-453/R-95-017), a %C_{3+} of 100%, and an estimated number of components.
[1] – Based on the screening value correlations and a screening value of 10,000 ppmv.
[2] – Based on the screening value correlations and a screening value of 500 ppmv.
[3] – Based on average refinery emission factor and a control efficiency of 98%.
[4] – Based on the screening value correlations and a screening value of 1,000 ppmv.
[5] – Based on the screening value correlations and a screening value of 2,000 ppmv.

Hydrogen Service Equipment Leak VOC Emissions from EUG 31/32/33/34

Number Items	Type of Equipment	Factor (kg/hr/source)	Emissions (TPY)
2,718	Gas/ Light-Liquid Valves[1]	0.00221	34.80
58	Pressure Relief Valves[2]	0.00320	1.08
7,342	Gas/Light-Liquid Flanges	0.00025	10.63
14	Compressor Seals[2]	0.01272	1.03
Total			**47.54**

Fugitive VOC emissions are based on factors derived from EPA's *1995 Protocol for Equipment Leak Emission Estimates* (EPA-453/R-95-017), a $\%C_{3+}$ of 0.6%, and an estimated number of components.

1 – Based on the screening value correlations and a screening value of 10,000 ppmv.

2 – Potential emissions are controlled at 98%.

Equipment Leak GHG Emissions from EUG 31/32/33/34 [1]

Number Items	Type of Equipment	Factor (kg/hr/source)	Emissions (CO_{2e} TPY)
18,289	Gas/ Light-Liquid Valves[2]	0.00221	487.87
3,433	Gas/ Light-Liquid Valves[3]	0.00024	9.94
292	Pressure Relief Valves[4]	0.00320	11.28
26	Pressure Relief Valves[5]	0.00309	0.97
58,248	Gas/Light-Liquid Flanges	0.00025	175.77
11	Compressor Seals[4]	0.01272	1.69
213	Light-Liquid Pump Seals[6]	0.00519	13.34
466	Other	0.00865	48.65
Total			**749.51**

Fugitive GHG emissions are based on factors derived from EPA's *1995 Protocol for Equipment Leak Emission Estimates* (EPA-453/R-95-017), a weighted average $\%CH_4$ of 5%, and an estimated number of components.

1 – Only the equipment in VOC gas or light liquid service were reviewed for CH_4 emissions.

2 – Based on the screening value correlations and a screening value of 10,000 ppmv.

3 – Based on the screening value correlations and a screening value of 500 ppmv.

4 – Based on average refinery emission factor and a control efficiency of 98%.

5 – Based on the screening value correlations and a screening value of 1,000 ppmv.

6 – Based on the screening value correlations and a screening value of 2,000 ppmv.

VOC Emissions from EUG 35 Wastewater Fugitive Equipment Leaks

Number Items[1]	Type of Equipment	Factor (kg/hr/source)	Emissions (TPY)
516	OWS Sewer Cups	0.032[2]	160.44

1 - Based on estimated source counts.

2 - This factor is a standardized emission factor from the preamble to NSPS, Subpart QQQ.

EUG 36/38 MPV Subject to Subpart CC

These emission units are required to be routed to a control device (EUG 14 unless otherwise specified in the specific conditions) and all emissions are incorporated into the control device emission estimates.

EUG 37 MPV Routed to FGRS

Since these emission units are routed to the fuel gas system, there are no estimated emissions for this EUG.

Criteria Pollutant Emissions from EUG 40 Wastewater Plant Transfer Pump's ICE [1]

	NO_X		CO		PM_{10}		SO_2		VOC	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
P850A [3]	1.02	4.47	0.67	2.96	0.05	0.24	0.00	0.00	0.20	0.89
P850B [2]	2.25	9.87	0.48	2.13	0.16	0.70	0.03	0.13	0.18	0.79
P850C [3]	0.99	4.34	0.65	2.87	0.05	0.23	0.00	0.00	0.20	0.87
P850D [3]	0.65	2.85	0.69	3.01	0.06	0.24	0.00	0.00	0.21	0.91
P850E [3]	1.26	5.52	0.95	4.17	0.08	0.34	0.00	0.01	0.29	1.26
FWPE-1 [4]	7.87	34.57	1.53	6.73	0.43	1.90	0.94	4.14	0.09	0.40
Totals	**14.04**	**61.62**	**4.97**	**21.87**	**0.83**	**3.65**	**0.97**	**4.28**	**1.17**	**5.12**

1 Annual emissions based on continuous operation (8,784 hours per year).

2 Based on AP-42 (10/1996), Section 3.3 and a fuel sulfur concentration of 0.05% by weight.

3 Based on the applicable Tier II or Tier III emission levels. Emissions of NO_X+HC are assumed to be NO_X. VOC emissions are estimated based on AP-42 (10/1996), Section 3.3. SO_2 emissions are based on a fuel sulfur concentration of 15 ppmw.

4 Emission factors for NO_X, CO, PM-10, and VOCs are based on manufacturer's data. The emission factor for SO_2 was obtained from AP-40 (10/1996), Section 3.3

40 CFR Part 89, Non-Road CI-RICE Emission Standards, g/kW-hr (g/hp-hr)

	Tier	kW	Model Years	NO_X+HC	CO	PM
A & C	II	$37 \geq kW < 75$	2004-2007	7.5 (5.6)	5.0 (3.7)	0.40 (0.30)
E	II	$75 \geq kW < 130$	2003-2006	6.6 (4.9)	5.0 (3.7)	0.40 (0.30)
D	III	$37 \geq kW < 75$	2008-2013	4.7 (3.5)	5.0 (3.7)	0.40 (0.30)

GHG Emissions from EUG 40

	CO_2	CH_4	N_2O	CO_{2e}
EU	**TPY**	**TPY**	**TPY**	**TPY**
P850A	414	0.017	0.003	414
P850B	363	0.015	0.003	364
P850C	401	0.016	0.003	401
P850D	421	0.017	0.003	422
P850E	576	0.023	0.005	577
FWPE-1	2,306	0.094	0.019	2,319
Totals	**2,183**	**0.182**	**0.036**	**2,189**

Emissions from the diesel fired engines are based on operating 8,784 hours a year, the listed ratings, a heat input of 7,000 BTU/hp-hr, Global Warming Potentials from Table A-1 of Subpart A of Part 98, and the following emission factors:

The default CO_2 emission factor for diesel from Table C-1 to Subpart C of Part 98.
The default N_2O and CH_4 emission factors for petroleum from Table C-2 to Subpart C of Part 98.

EUG 41 Startup, Shutdown, and Maintenance (SSM)

The nature of refining operations requires certain activities that are outside normal continuous operations. These activities result in air emissions that exceed the emission rate of normal operations. Based on historical inventory records, these startup shutdown, and maintenance emissions are estimated as follows:

Startup, Shutdown, and Maintenance (SSM) Emissions (Tons) per Event

Event (EU)	CO	NO_X	SO_2	PM_{10}	VOC	H_2S	HF
FCCU Startup (FGS-200)	1.90	NA	NA	NA	NA	NA	NA
FCCU Shutdown (FGS-200)	1.40	0.40	NA	NA	NA	NA	NA
CFHT & Hydrocracker Shutdown (HI-81001)	0.50	0.08	0.25	NA	NA	NA	NA
C-114 Shutdown (HI-81003)	0.50	0.08	0.25	NA	NA	NA	NA
Misc. Refinery Unit Start Up (HI-81001 & HI-81003)	0.40	0.06	0.25	0.10	0.12	NA	NA
Misc. Refinery Unit Shut Down (HI-81001 & HI-81003)	0.40	0.06	0.25	0.10	0.12	NA	NA
Refinery Turnaround Depressurization (Fugitive)	NA	NA	NA	NA	36.0	0.10	0.05
Tank degassing, changes in service, maintenance (Fugitive)	NA	NA	NA	NA	2.00	0.03	NA

* These emissions do not include insignificant or trivial activities.

PM_{10} and VOC Emissions from EUG 42A, 42B, 42C, and 42D

		PM_{10}		VOC	
EU	**Description**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
C-150001	CFHT Induced Draft Cooling Tower	7.29	31.93	125.60	48.66
C-1501	Ceramic Induced Draft Cooling Tower	2.81	12.31	53.93	7.08
C-150005	Alkylation Induced Draft Cooling Tower	5.83	25.54	100.48	38.93
C-150006	STG Induced Draft Cooling Tower	9.40	41.19	162.02	62.77
Totals		**25.33**	**110.96**	**442.04**	**157.43**

Emissions from the cooling towers are based on a circulation rate of 20,000 gallons per minute (gpm) for the CFHT Cooling Tower (C-150001), 8,500 gpm for the Ceramic Cooling Tower (C-1501), 16,000 gpm for the Alky Cooling Tower (C-150005), and 25,800 gpm for the STG Cooling Tower (C-150006).

PM_{10} emissions were estimated using an empirically derived drift factor (2,632 lb H_2O drift/10^6 gal. cooling tower circulation rate), a total dissolved solids (TDS) concentration of 2,093 ppmw (Ceramic Tower) and 2,308 ppmw (CFHT Tower, Alky Tower, and STG Tower), and assuming all solids are emitted as PM_{10}.

Annual VOC emissions were estimated using annual average strippable VOC concentrations of 0.38 ppmw (Ceramic Tower) and 1.11 ppmw (CFHT Tower, Alky Tower, and STG Tower).

Hourly VOC emissions were estimated using maximum hourly strippable VOC concentrations of 12.68 ppmw (Ceramic Tower) and 12.55 ppmw (CFHT Tower, Alky Tower, and STG Tower).

Strippable VOC emissions were estimated a mass-balance approach for a simulated air stripper with a 20:1 air to liquids volumetric flow ratio. Annual emission rates were computed using the average return air stripped VOC concentrations for each tower (28.5 ppmv for the Ceramic Cooling Tower and 84.25 ppmv for the Alky Cooling Tower), and the average return sample temperature (69.3ºF for the Ceramic Cooling Tower and 73.38ºF for the Alky Cooling Tower). Hourly emission rates were computed using the maximum return air stripped VOC concentrations for each tower (1,000 ppmv for each tower), and the maximum return sample temperature (95.0ºF for the Ceramic Cooling Tower and 101.0ºF for the Alky Cooling Tower). Emissions from the CFHT Cooling Tower and the STG Cooling Tower used the strippable VOC concentrations established for the Alky Tower.

Facility Wide Criteria Pollutant Emissions

	NO_X		CO		PM_{10}		SO_2		VOC	
EUG	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
1	----	----	----	----	----	----	----	----	----	121.76
2	----	----	----	----	----	----	----	----	----	10.32
3	----	----	----	----	----	----	----	----	----	3.99
5	----	----	----	----	----	----	----	----	----	23.55
6	----	----	----	----	----	----	----	----	----	14.68
7	----	----	----	----	----	----	----	----	----	4.79
9	161.99	590.60	126.37	443.24	14.80	55.90	51.22	224.4	10.71	36.05
10	3.99	17.47	4.03	17.65	0.75	3.29	3.35	14.67	0.54	2.37
11	30.50	103.46	26.27	88.55	2.37	8.02	8.22	36.04	1.72	5.80
12	3.39	12.49	4.90	16.48	0.44	1.49	1.20	5.27	0.32	1.08
13	----	3.47	----	4.80	----	0.43	----	0.44	----	0.31
13B	12.84	35.01	12.84	56.23	2.36	6.44	8.37	13.59	1.71	7.49
14	66.28	27.73	360.63	150.93	8.10	3.37	32.74	13.71	136.46	57.11
15/23	5.90	25.85	4.42	19.33	0.73	3.20	38.18	167.2	0.27	1.31
16/24	9.37	41.05	6.67	22.47	1.14	3.84	8.00	35.03	0.34	1.47
17	5.20	15.79	13.00	39.48	0.00	0.00	0.01	0.01	30.16	73.66
18/19/25	118.0	344.8	178.1	234.7	22.83	53.35	66.44	223.6	0.78	3.40
20	101.81	12.73	128.19	29.14	2.88	0.37	0.09	0.08	5.07	0.95
22	15.50	31.00	3.34	6.68	1.10	2.20	0.01	0.01	1.26	2.51
24	1.19	5.21	0.44	1.93	0.56	2.46	0.67	2.91	0.05	0.20
26	----	26.66	----	5.48	----	0.50	----	16.32	----	33.00
27	0.10	0.12	0.54	0.63	0.01	0.01	----	----	1.10	1.29
28	----	----	----	----	----	----	----	----	----	0.95
29	----	----	----	----	----	----	----	----	----	45.92
30	----	----	----	----	----	----	----	----	----	16.69
31-34	----	----	----	----	----	----	----	----	----	743.52
35	----	----	----	----	----	----	----	----	----	160.44
40	14.04	61.52	4.97	21.85	0.83	3.64	2.47	4.47	1.17	5.12
42A	----	----	----	----	7.29	31.93	----	----	125.60	48.66
42B	----	----	----	----	2.81	12.31	----	----	53.93	7.08
42C	----	----	----	----	5.83	25.54	----	----	100.48	38.93
42D	----	----	----	----	9.40	41.19	----	----	162.02	62.77
TOTALS	**550.1**	**1,355.0**	**874.7**	**1,159.6**	**84.2**	**259.5**	**221.0**	**757.8**	**633.7**	**1,537.2**

Facility Wide GHG Emissions

	CO_2		N_2O		CH_4		CO_{2e}	
EUG	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
1-7	----	----	----	----	----	98	----	98
9	191,868	840,379	103	445	37	156	192,008	840,980
10	10,993	48,150	7	29	2	10	11,002	48,189
11	----	----	----	----	----	----	----	118,945
12	5,102	22,344	3	14	1	6	5,106	22,364
13	----	----	----	----	----	----	----	6,277
13B	----	----	----	----	----	----	----	163,686
14	141,293	59,036	64	27	205	88	143,387	59,151
15/23	10,998	38,538	0	0	0	0	10,998	38,538
16/24	13,616	47,709	----	----	400	1,400	14,016	49,109
17	6,648	13,295	17	34	7	14	6,672	13,343
18	177,090	620,522	715	2,508	392	1,375	178,197	624,405
19	15,878	69,546	9	41	3	14	15,890	69,601
20	5,104	669	10	1	4	0	5,120	670
22	571	1,141	1	3	1	1	573	1,145
24	301	1,057	1	2	0	1	302	1,060
26	13,239	57,987	43	187	25,361	111,080	28,144	123,271
27	3	0	0	0	0	0	3	0
31-34	----	----	----	----	----	----	----	737.99
40	497	2,183	0	5	0	1	497	2,189
TOTALS	**593,201**	**1,822,556**	**973**	**3,296**	**26,413**	**114,244**	**611,915**	**2,183,759**

SECTION VI. INSIGNIFICANT ACTIVITIES (ISA)

The ISA identified and justified in the application are duplicated below. Any activity to which a state or federal applicable requirement applies is not insignificant even if it is included on the ISA list. Activities requiring records of hours, quantity, or capacity to verify emissions are below the de minimis are identified below with an asterisk "*". Recordkeeping is not required for those operations, which qualify as Trivial Activities. Appropriate recordkeeping conditions are specified in the Specific Conditions.

1. Space heaters, boilers, process heaters, and emergency flares less than or equal to 5 MMBTUH heat input (commercial natural gas). This facility has some small heaters rated less than 5 MMBTUH.

2. ***** Emissions from fuel storage/dispensing equipment operated solely for facility owned vehicles if fuel throughput is not more than 2,175 gallons/day, averaged over a 30-day period. This facility has company vehicle/equipment fueling station which does not exceed 2,175 gallons/day.

3. * Emissions from storage tanks constructed with a capacity less than 39,894 gallons which store VOC with a vapor pressure less than 1.5 psia at maximum storage temperature. This facility has some storage tanks with capacities of less than 39,894 gallons which store VOC with vapor pressures less than 1.5 psia.

4. Cold degreasing operations utilizing solvents that are denser than air. This facility has some cold degreasing operations utilizing solvents that are denser than air.

5. Welding and soldering operations utilizing less than 100 pounds of solder and 53 tons per year of electrodes. Welding and soldering are conducted at the facility but are conducted as a part of routine maintenance and is considered a trivial activity and recordkeeping will not be required in the Specific Conditions.

6. Torch cutting and welding of under 200,000 tons of steel fabricated per year. Torch cutting and welding are conducted at the facility but are conducted as a part of routine maintenance and are considered a trivial activity and recordkeeping will not be required in the Specific Conditions.

7. Emissions from the operation of groundwater remediation wells including but not limited to emissions from venting, pumping, and collecting activities subject to de minimis limits for air toxics (252:100-41-43) and HAPs (§ 112(b) of CAAA90). The refinery has these types of wells as a result of RCRA remediation/monitoring activities.

8. Hazardous waste and hazardous materials drum staging areas. This facility has a hazardous materials collection system and satellite collection locations throughout the facility.

9. Exhaust systems for chemical, paint, and/or solvent storage rooms or cabinets, including hazardous waste satellite (accumulation) areas. This facility has storage cabinets and rooms with room exhaust points for chemicals and solvents.

10. * Activities that have the potential to emit no more than 5 TPY (actual) of any criteria pollutant. Others may be identified and used in the future.

SECTION VII. OKLAHOMA AIR POLLUTION CONTROL RULES

OAC 252:100-1 (General Provisions) [Applicable]
Subchapter 1 includes definitions but there are no regulatory requirements.

OAC 252:100-2 (Incorporation by Reference) [Applicable]
This subchapter incorporates by reference applicable provisions of Title 40 of the Code of Federal Regulations. These requirements are addressed in the "Federal Regulations" section.

OAC 252:100-3 (Air Quality Standards and Increments) [Applicable]
Primary Standards are in Appendix E and Secondary Standards are in Appendix F of the Air Pollution Control Rules. At this time, all of Oklahoma is in attainment of these standards.

OAC 252:100-5 (Registration, Emission Inventory, and Annual Fees) [Applicable]
The owner or operator of any facility that is a source of air emissions shall submit a complete emission inventory annually on forms obtained from the Air Quality Division. This facility has recently submitted the required emission inventories and has paid the applicable or fees.

OAC 252:100-8 (Permits for Part 70 Sources) [Applicable]
Part 5 includes the general administrative requirements for part 70 permits. Any planned changes in the operation of the facility which result in emissions not authorized in the permit and which exceed the "Insignificant Activities" or "Trivial Activities" thresholds require prior notification to AQD and may require a permit modification. Insignificant activities mean individual EU that either are on the list in Appendix I (OAC 252:100) or whose actual calendar year emissions do not exceed the following limits:

1. 5 TPY of any one criteria pollutant
2. 2 TPY of any one hazardous air pollutant (HAP) or 5 TPY of multiple HAPs or 20% of any threshold less than 10 TPY for single HAP that the EPA may establish by rule

Emission and operating limitations have been established based on information submitted in applications for a number of permits issued prior to this Title V operating permit renewal. In some cases, the limitations came directly from federal rules (NSPS or NESHAP). In cases where construction permits were used as the basis for emission limitations, the specific conditions in this operating permit cite those earlier construction permits. Construction permits issued subsequent to the last operating permit update [Permit No. 2012-1523-TVR (M-1)] include the following: 2012-1523-C (M-2), 2012-1523-C (M-4), 2012-1523-C (M-5), and 2012-1523-C (M-7).

OAC 252:100-9 (Excess Emission Reporting Requirements) [Applicable]
Except as provided in OAC 252:100-9-7(a)(1), the owner or operator of a source of excess emissions shall notify the Director as soon as possible but no later than 4:30 p.m. the following working day of the first occurrence of excess emissions in each excess emission event. No later than thirty (30) calendar days after the start of any excess emission event, the owner or operator of an air contaminant source from which excess emissions have occurred shall submit a report for each excess emission event describing the extent of the event and the actions taken by the owner or operator of the facility in response to this event. Request for mitigation, as described in OAC 252:100-9-8, shall be included in the excess emission event report. Additional reporting may be required in the case of ongoing emission events and in the case of excess emissions reporting required by 40 CFR Parts 60, 61, or 63.

OAC 252:100-13 (Open Burning) [Applicable]
Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in this subchapter.

OAC 252:100-17 (Incinerators) [Not Applicable]
This subchapter specifies design and operating requirements and emission limitations for incinerators, municipal waste combustors, hospital, medical, and infectious waste incinerators, and commercial, industrial, and other solid waste incineration units. Thermal oxidizers, flares, and any other air pollution control devices are exempt from Part 1 of this subchapter for incinerators.

This facility does not have any municipal waste combustors, hospital, medical, and infectious waste incinerators, or commercial, industrial, or other solid waste incineration units including air curtain incinerators. The incinerators at the refinery are considered thermal oxidizers, flares, and other air pollution control devices.

OAC 252:100-19 (Particulate Matter) [Applicable]
This subchapter specifies a particulate matter (PM) emission limitation of 0.6 lb/MMBTU from fuel-burning units with a rated heat input of 10 MMBTUH or less. All of the small (<10 MMBTUH) fuel-burning units are fired with refinery fuel-gas or diesel fuel.

Particulate emission limits are based on the maximum design heat input rating. For fuel-burning units rated less than 1,000 MMBTUH but greater than 10 MMBTUH, the allowable PM emissions are calculated using the formula: $E = 1.042808\ X^{(-0.238561)}$, where E is the limit in lb/MMBTU and X is the maximum rated heat input.

Fuel-burning unit is defined as "any internal combustion engine or gas turbine or any other combustion device used to convert the combustion of fuel into usable energy." Since thermal oxidizers, flares, and incinerators are pollution control devices designed to destroy pollutants and are not used to convert fuel into usable energy, they do not meet the definition of fuel-burning unit and are not subject to these requirements. The FCCU regenerators and the CCR also do not convert combustion of fuel into usable energy, except for the CO boilers, therefore, they are also not considered fuel-burning units. The following tables list all fuel-burning equipment affected by this permit and their associated emissions.

EU	Description Boilers	Rating MMBTUH	SC 19 Limit lb/MMBTU	Emissions lb/MMBTU
B-253A	CO Boiler	144.0	0.32	0.01
B-253B	Boiler/CO Boiler	144.0	0.32	0.01
B-801	Boiler	72.5	0.38	0.01
B-802	Boiler	89.8	0.36	0.01
B-803	Boiler	86.8	0.36	0.01
B-15001	Boiler	285.3	0.27	0.01
H-101	Process Heater	30.8	0.46	0.01
H-102A	Process Heater	160.0	0.31	0.01
H-102B	Process Heater	135.0	0.32	0.01
H-103	Process Heater	102.6	0.35	0.01
H-201	Process Heater	116.7	0.34	0.01
H-301	Process Heater	21.6	0.50	0.01
H-401A	Process Heater	16.0	0.54	0.01
H-401B	Process Heater	14.8	0.55	0.01
H-402A	Process Heater	13.9	0.56	0.01
H-402B	Process Heater	15.8	0.54	0.01
H-403	Process Heater	98.7	0.35	0.01
H-404/5	Process Heater	99.3	0.35	0.01
H-406	Process Heater	28.0	0.47	0.01
H-411	Process Heater	28.0	0.47	0.01

EU	Description Boilers	Rating MMBTUH	SC 19 Limit lb/MMBTU	Emissions lb/MMBTU
H-601	Process Heater	58.5	0.40	0.01
H-603	Process Heater	125.5	0.33	0.01
H-901	Process Heater	60.0	0.39	0.01
H-1016	Process Heater	4.8	0.60	0.01
H-2601	Process Heater	13.2	0.56	0.01
H-5602	Hot Oil Heater	20.0	0.51	0.01
H-6501	Process Heater	99.7	0.35	0.01
H-6502	Process Heater	54.3	0.40	0.01
H-6701	Co-Processor Heater	11.8	0.59	0.01
H-15001	Process Heater	326.8	0.26	0.01
H-100024	Asphalt Tank Heater	13.5	0.56	0.01
H-210001	Process Heater	12.2	0.57	0.01
	Diesel-Fired Engines			
EEQ-8801	DMT/DMT-825D2	5.1	0.60	0.10
P1806	Cummins NT-855-F2	3.0	0.60	0.10
P1807A	Caterpillar 3412 HRM	4.7	0.60	0.10
P1807B	Caterpillar 3412 HRM	4.7	0.60	0.10
P1807C	Caterpillar 3412 HRM	4.7	0.60	0.10
EG1880-01	Cummins WSG-1068	0.8	0.60	0.31
C-80018	Cummins N14-C475	3.6	0.60	0.10
P850A	Deutz F4914	0.6	0.60	0.31
P850B	Deutz F4912	0.5	0.60	0.31
P850C	John Deere 4045DF 270B	0.6	0.60	0.31
P850D	John Deere 4045TF 280B	0.6	0.60	0.31
P850E	John Deere 4045TF 275B	0.8	0.60	0.31
FWPE-1	Caterpillar 3406 C	3.2	0.60	0.10
EG-ADMIN	Cummins QSX15-G9	3.9	0.60	0.10
	Gas-Fired Engines			
EG1880-02	Cummins QSTB-G5	1.0	0.60	0.01

AP-42 (7/98), Section 1.4, Table 1.4-2, lists the total PM emissions for natural gas to be 7.6 lb/MMft^3 or about 0.0076 lb/MMBTU. The permit requires the heaters and boilers to be fired with either refinery fuel-gas or commercial grade natural gas to ensure compliance with Subchapter 19. Since all of the emission limits for the heaters and reboilers under Subchapter 19 are greater than the expected emissions from these units, having the permit require these units to only be fueled with refinery fuel gas or commercial grade natural gas will ensure compliance with this subchapter. AP-42 (10/96), Section 3.3, lists the total PM emissions from small diesel-fired engines as 0.31 lb/MMBTU. AP-42 (10/96), Section 3.4, Table 3.4-1, lists the total PM emissions for large diesel-fired engines to be 0.1 lb/MMBTU. The permit requires the use of diesel fuel in the compression ignition (CI) RICE to ensure compliance with Subchapter 19.

For 4-cycle rich-burn and lean-burn engines burning natural gas, AP-42 (7/00), lists the total PM emissions as approximately 0.02 and 0.01 lb/MMBTU, respectively. The permit requires spark ignition (SI) ICE to be fired with natural gas to ensure compliance with Subchapter 19.

This subchapter also limits emissions of PM from directly fired fuel-burning units and industrial processes based on their process weight rates. For process rates up to 60,000 lb/hr (30 TPH), the allowable emission rate (E) in pounds per hour is interpolated using the formula in Appendix G ($E = 4.10*P^{(0.67)}$) where (P) is the process weight rate in tons per hour. For process rates in excess of 60,000 lb/hr (30 TPH), extrapolation of the allowable emission limit is accomplished using this equation ($E = 55.0*P^{(0.11)}-40$). Emission limits established by Subchapter 19 include the front-half and back-half of the PM sampling train. Therefore, representative emissions from these emission units include the anticipated emissions from both the front-half and the back-half of the sampling train and are greater than the limits that will be established in the permit. Listed in the following table are the process weight rates for the EU affected by this permit, the estimated emissions, and the allowable emission limits.

EU	Source	Rate (TPH)	SC 19 Limit (lb/hr)	Emissions (lb/hr)
HI-801	Asphalt Blowstill & TO	10.64	19.99	0.69
FGS-200	FCCU Regenerators[1]	1,443	82.43	51.34
Cat_Hop	FCCU Catalyst Hopper Vent	700	73.06	3.77
HI-501	#1 SRU Incinerator	5.45	15.40	0.43
CCR	Platformer CCR Vent	0.50	2.58	0.56
HI-5602	#2 SRU/TGTU w/Incinerator	21.2	31.73	0.40
HI-8801	WWTP Incinerator	0.01	0.23	0.12
LPLT	LPLT Vapor Combustor	0.70	3.22	0.77

[1] - Based only on the catalyst recirculation rate.

The Asphalt Blowstill thermal oxidizer, WWTP Incinerator, and LPLT Vapor combustor only combust waste gases and no specific requirements are needed for these emission units to ensure compliance with this subchapter. The FCCU Regenerators and Catalyst Hopper will be vented to a WS. The permittee monitors and records the WS operating parameters to ensure proper operation of the WS and compliance with this subchapter. The SRU tail gas incinerators combust waste gases and refinery fuel-gas as auxiliary fuel and no specific requirements are needed for these emission units to ensure compliance with this subchapter. PM emissions from the Platformer CCR are controlled using a series of internal screens and cyclones. Since the catalyst is very expensive, every effort is made to recover it and minimize air emissions. The CCR is subject to NESHAP, Subpart UUU and is vented to a wet scrubber to control emissions of HCl. Therefore, monitoring under the NESHAP will ensure compliance with this subchapter.

OAC 252:100-25 (Visible Emissions and Particulate Matter) [Applicable]
No discharge of greater than 20% opacity is allowed except for short-term occurrences, which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case, shall the average of any six-minute period exceed 60% opacity.

EU subject to an opacity limit under NSPS are exempt from the requirements of this subchapter. The FCCU is subject to an opacity limit under NSPS, Subpart J. The LPLT Vapor Combustor is subject to a no visible emission limit under NESHAP, Subpart A and will comply with this subchapter. Engines subject to NSPS, Subpart IIII are subject to an opacity limit under NSPS and are not subject to this subchapter.

When burning refinery fuel-gas in the combustion units (process heaters, boilers, flares, and ICE) there is little possibility of exceeding the opacity standards. The # 1 & #2 SRU/TGTU and WWTP Incinerator combust waste gases and refinery fuel gas and have little possibility of exceeding the opacity standards. When burning diesel in the CI-ICE, there is little possibility of exceeding the opacity standards. The Platformer CCR is vented to a wet scrubber and also has very little possibility of exceeding the opacity standards.

For the Asphalt Blowstill, the permit will require a daily observation of the stack and opacity readings to be conducted if visible emissions are detected.

This subchapter requires owners or operators of the following emission sources to install, calibrate, operate, and maintain all monitoring equipment necessary for continuously monitoring opacity:

1. Fluid bed catalytic cracking unit catalyst regenerators at petroleum refineries as specified in paragraph 2.4 of 40 CFR Part 51, Appendix P; and
2. Fossil fuel-fired steam generators with a design heat input value of 250 MMBTUH or more and that does not burn gaseous fuel exclusively; and
3. Any fuel-burning equipment with a design heat input value of 250 MMBTU/hr or more that does not burn gaseous fuel exclusively, and that was not in being on or before July 1, 1972 or that is modified after July 1, 1972.

This section shall not apply to such emission sources that are subject to a NSPS. The FCCU is subject to NSPS and is not subject to the continuous opacity monitoring required by this subchapter. There are no fossil fuel fired steam generators with a design heat input value of 250 MMBTUH or more and that does not burn gaseous fuel exclusively. The only fuel-burning equipment with a heat input greater than 250 MMBTUH is H-15001 (326.3 MMBTUH) but it is fired exclusively with gaseous fuel and is not subject to the continuous opacity monitoring required by this subchapter.

OAC 252:100-29 (Fugitive Dust) [Applicable]
No person shall cause or permit the discharge of any visible fugitive dust emissions beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. Under normal operating conditions, this facility will not cause a problem in this area, therefore it is not necessary to require specific precautions to be taken.

OAC 252:100-31 (Sulfur Compounds) [Applicable]
Part 2 limits the ambient air impact of H_2S emissions from any new or existing source to 0.2 ppm based on a 24-hour average. Emissions from all of the equipment have been modeled using AERMOD and have been shown to be in compliance with the standard as shown below.

Ambient Impacts of H_2S

Averaging Time	Standard μg/m³	Impact μg/m³
24-hour	279	22

Part 3 requires any fossil fuel-fired steam generator, that was in being on or before July 1, 1972, and that utilizes an air pollution abatement operation to reduce the emissions of SO_2, to install, calibrate, maintain, and operate a continuous SO_2 emissions monitoring system. There are no fossil fuel-fired steam generators located at this facility that were in being on or before July 1, 1972, and that uses an air pollution abatement operation to reduce the emissions of SO_2.

Part 5 limits SO_2 emissions from new fuel-burning equipment (constructed after July 1, 1972). For gaseous fuels the limit is 0.2 lb/MMBTU heat input. For fuel gas with a heat content of 1,000 BTU/SCF, this is equivalent to approximately 1,185 ppmv sulfur in the fuel gas. All fuel-burning equipment constructed or modified after June 11, 1973, which combust refinery fuel gas are subject to NSPS, Subpart J, which limits the amount of H_2S in the fuel gas to 0.1 grains/DSCF or approximately 159 ppmv. The refinery fuel gas has a HHV of approximately 800 BTU/SCF, which is equivalent to approximately 0.0336 lb SO_2/MMBTU. Commercial natural gas contains less than 4 ppmdv of sulfur, has a heat content of approximately 1,020 BTU/SCF (HHV), and emissions of approximately 0.0006 lb/MMBTU.

For liquid fuels the limit is 0.8 lb/MMBTU. All liquid fuels combusted at the facility are low-sulfur fuel oil with a maximum sulfur content of 0.05 percent by weight. AP-42 (5/2010), Chapter 1.3, Table 1.3-1, gives an emission factor of 142*S pound of SO_2 per 1,000 gallons which is approximately 0.05 lb/MMBTU when S = 0.05% by weight sulfur in the fuel oil. This emission rate is in compliance with the limitation of 0.8 lb/MMBTU.

The permit will require all new fuel-burning equipment to be fired with either refinery fuel gas, with a limit of 0.1 grains/DSCF, commercial grade natural gas, or fuel oil with a maximum sulfur content of 0.05 % sulfur by weight.

Part 5 requires H_2S contained in the waste gas stream from any petroleum or natural gas process equipment shall to be reduced by 95% by removal or by being oxidized to SO_2 prior to being emitted to the ambient air. This requirement does not apply if a facility's emissions of H_2S do not exceed 0.3 lb/hr, two-hour average. The owner or operator shall install, maintain, and operate an alarm system that will signal a malfunction for all thermal devices used to control H_2S emissions from petroleum and natural gas processing facilities regulated under OAC 252:100-26(1).

Emissions from the liquid sulfur storage pit (SSP520), liquid sulfur storage vessel, and the regenerated amine storage vessels (V-523) are estimated below the exemption level. However, the liquid sulfur storage vessel is vented to the SRU incinerator (HI-5602) or the front end of the SRU. The railcar loading operations (LR-SB001 & MSLA-520) are calculated to have emissions of approximately 0.58 lb/hr/railcar based on the maximum loading rate and are subject to this requirement.

The following requirements apply to any gas sweetening unit or petroleum refinery process equipment with a sulfur content of greater than 0.54 LT/D in the acid gas stream or with an emission rate of 100 lb/hr or less of SO_X expressed as SO_2, two-hour average. Sulfur recovery units operating in conjunction with any refinery process shall have the sulfur recovery efficiencies required in OAC 252:100-31-26(2)(C) through (2)(F). When the sulfur content of the acid gas stream from a gas sweetening unit or refinery process is greater than 5.0 LT/D but less than or equal to 150.0 LT/D, the required recovery efficiency of the sulfur recovery unit shall be calculated using the following formula, where Z is the minimum sulfur recovery efficiency required and X is the sulfur feed rate, expressed in LT/D of sulfur and rounded to one decimal place:
$Z = 92.34\ X^{0.00774}$.

The #1 SRU has a capacity of approximately 119 LTD and the #2 SRU has a capacity of approximately 130 LTD. The required SO_2 reduction efficiency for these units using the formula are 95.8% and 95.9%, respectively. The SRU reduction efficiencies are expected to exceed 98% and 99.8%, respectively. All applicable requirements will be incorporated into the permit.

OAC 252:100-33 (Nitrogen Oxides) [Applicable]
NO_X emissions are limited to 0.20 lb/MMBTU heat input, three hour average, from all gas-fired fuel-burning equipment constructed after February 2, 1972, with a rated heat input of 50 MMBTUH or greater. The FCCU regenerators, CCR, and incinerators do not meet the definition of fuel-burning equipment and are not subject to this subchapter. All of the fuel-burning equipment rated greater than 50 MMBTUH are listed below in the table. All emissions from the heaters and boilers are in compliance with this subchapter.

EU	Description Heaters/Boilers	Const./Mod. Date	Rating MMBTUH	SC 33 Limit lb/MMBTU	Emissions lb/MMBTU
H-102A	Process Heater	1998	160.0	0.20	0.045
H-102B	Process Heater	1998	135.0	0.20	0.059
H-103	Process Heater	1974	102.6	0.20	0.186
H-201	Process Heater	1974	116.7	0.20	0.098
H-403	Process Heater	1975	98.7	0.20	0.098
H-404/5	Process Heater	1980	99.3	0.20	0.098
H-601	Process Heater	1974	58.5	0.20	0.098
H-603	Process Heater	1992	125.5	0.20	0.066
H-901	Process Heater	1969	60.0	0.20	0.098
H-6501	Process Heater	2008	99.7	0.20	0.040
H-6502	Process Heater	1992	54.3	0.20	0.060
H-15001	Process Heater	1992	326.8	0.20	0.060
B-253A	CO Boiler	2005	144.0	0.20	0.060
B-253B	Boiler/CO Boiler	2005	144.0	0.20	0.060
B-801	Boiler	1974	72.5	0.20	0.098
B-802	Boiler	1975	89.8	0.20	0.098
B-803	Boiler	1975	86.8	0.20	0.098
B-15001	Boiler	2015	285.3	0.20	0.045

OAC 252:100-35 (Carbon Monoxide) [Applicable]
Subchapter 35 requires new petroleum catalytic cracking and petroleum reforming units to reduce CO emissions by use of complete secondary combustion of the waste gas generated. Removal of 93 percent or more of the carbon monoxide generated is considered equivalent to secondary combustion. The FCCU Regenerators are subject to this subchapter. The FCCU No. 1 Regenerator reduces CO emissions by secondary combustion in the CO Boilers. The FCCU No. 2 Regenerator is a full combustion unit with CO emissions at or near the detection limit. The FCCU No. 2 Regenerator combusts the remaining coke from the catalyst that was not combusted in the FCCU No. 1 Regenerator.

While this rule is not specific about compliance with the alternative standard for OAC 252:100-35, the intent of the regulation is to reduce emissions of CO to a level which is represented by complete combustion. Complete combustion of CO can be shown in other ways such as through operational parameters and exhaust gas CO concentrations. Based on average combustion processes, CO emissions from combustion units that are operating properly average 500 ppmv and range from 1,000 to 50 ppmv.

Operation of the FCCU No. 1 and 2 Regenerators within the established NSPS, Subpart J, CO limit of 500 ppmv in the exhaust gases should assure compliance with the intent of Subchapter 35 (complete combustion).

The Platformer CCR is considered a petroleum catalytic reforming unit and is also subject to this subchapter. Compliance with a CO limit of 0.44 lb/hr in the exhaust gases from the regenerator should assure compliance with the intent of Subchapter 35. The specific conditions include a requirement to show compliance with the emission limit quarterly.

OAC 252:100-37 (Volatile Organic Compounds) [Applicable]
Part 1 requires all vapor-loss control devices, packing glands, and mechanical seals required by this subchapter to be properly installed, maintained, and operated.

Part 3 requires storage vessels constructed after December 28, 1974, with a capacity of 400 gallons or more and storing a VOC with a vapor pressure greater than 1.5 psia at maximum storage temperature to be equipped with a permanent submerged fill pipe or with an organic vapor recovery system. Storage vessels subject to the equipment standards of NSPS, Subparts K, Ka, or Kb are exempt from these requirements.

Most of the storage vessels constructed after December 28, 1974, with a capacity of 400 gallons or more, and storing a VOC with a vapor pressure greater than 1.5 psia are subject to NSPS and are exempt from this rule. However, there are a few tanks which are subject to these requirements which are listed below.

EU	Point	Roof Type	Contents	Barrels	Const. Date
TK-13006	P8	Cone	Fuel Additives	485	1993
TK-13005	ISA	Cone	Fuel Additives	49	1993
TK-13007	ISA	Cone	Fuel Additives	49	1996
TK-13008	ISA	Cone	Fuel Additives	49	1996

EU	Point	Roof Type	Contents	Barrels	Const. Date
TK-13009	ISA	Cone	Fuel Additives	49	1996
JFP1	ISA	Cone	Gasoline	52	1993
JFP2	ISA	Cone	Red Dye	11	1993

Part 3 requires storage vessels constructed after December 28, 1974, with a capacity of 40,000 gallons or more and storing a VOC with a vapor pressure greater than or equal to 1.5 psia to be a pressure vessel or to be equipped with an external floating roof or a fixed roof with an internal floating cover, or to be equipped with a vapor recovery system capable of collecting 85% of the uncontrolled VOC. Storage vessels subject to the equipment standards of NSPS, Subparts K, Ka, or Kb are exempt from these requirements.

All of the storage vessels constructed after December 28, 1974, with a capacity of 40,000 gallons or more, and storing a VOC with a vapor pressure greater than or equal to 1.5 psia are subject to NSPS and are exempt from this rule.

Even though the overlap requirements of NESHAP, Subpart CC state that specific storage vessels that are subject to NSPS, Subparts K, Ka, and NESHAP, Subpart CC are only required to comply with the requirements of NESHAP, Subpart CC, the tanks are still considered subject to NSPS for this subchapter and are exempt from the requirements of this subchapter.

Part 3 applies to VOC loading facilities constructed after December 24, 1974. Facilities with a throughput greater than 40,000 gallons/day are required to be equipped with a vapor-collection and disposal system unless all loading is accomplished by bottom loading with the hatches of the tank truck or trailer closed. In either loading system, a means must be provided to prevent VOC drainage from the loading device when it is removed from any tank truck or trailer, or to accomplish complete drainage before removal. Loading facilities subject to the requirements of NSPS, Subpart XX or NESHAP, Subpart R are exempt from these requirements.

The light products loading terminal at the refinery is equipped with a vapor-collection and disposal system and the VOC railcar loading terminal will be equipped with a vapor-collection and disposal system. These terminals are also subject to NESHAP, Subpart R and are exempt from these requirements. The LPG loading facility is accomplished by bottom loading with the hatches of the tank truck or trailer closed. Also, the fittings used to connect to the tank truck or trailer are dry-disconnect couplings performing at a 2 cm^3 release per loading disconnect.

Part 5 limits the VOC content of coatings used in coating operations or lines. This facility does not normally conduct coating or painting operations except for routine maintenance of the facility and equipment, which is exempt.

Part 7 requires all VOC gases from a vapor recovery blowdown system to be burned by a smokeless flare or equally effective control device unless it is inconsistent with the "Minimum Federal Safety Standards for the Transportation of Natural and Other Gas by Pipeline" or any State of Oklahoma regulatory agency. This facility flares all emissions that are not processed by a vapor recovery system.

Part 7 requires fuel-burning and refuse-burning equipment to be operated and maintained so as to minimize emissions of VOC. Temperature and available air must be sufficient to provide essentially complete combustion. All equipment at the refinery is operated to minimize emissions of VOC.

Part 7 requires any single or multiple-compartment VOC/water separator that receives effluent water containing more than 200 gallons per day of any VOC, from any equipment processing, refining, storing, or handling VOC to comply with one of the following sets of conditions:

1. The container shall totally enclose the liquid contents and all openings shall be sealed;
2. The container shall be equipped with an external floating roof with a pontoon type or double deck type cover, or a fixed roof with an internal floating cover. The cover shall rest on the surface of the contents and be equipped with a closure seal, or seals, to close the space between the cover and container wall;
3. The container shall be equipped with a vapor recovery system that consists of a vapor-gathering system capable of collecting the VOC vapors and gases discharged and a vapor-disposal system capable of processing such vapors and gases to prevent their emission to the atmosphere; or
4. The container is approved prior to use and is equipped with controls that have efficiencies equal to the controls in listed in OAC 252:100-37(1-3).

For each of the systems, all gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place and the oil removal devices shall be gas-tight except when manual skimming, inspection and/or repair are in progress.

The oil-water separators (V-8801 & V-8802) are equipped with external floating roofs and are subject to NSPS, Subpart QQQ which requires controls equal to or greater than the requirements of OAC 252:100-37(1-3).

OAC 252:100-42 (Toxic Air Contaminants (TAC)) [Applicable]
This subchapter regulates toxic air contaminants (TAC) that are emitted into the ambient air in areas of concern (AOC). Any work practice, material substitution, or control equipment required by the Department prior to June 11, 2004, to control a TAC, shall be retained, unless a modification is approved by the Director. Since no AOC has been designated there are no specific requirements for this facility at this time.

OAC 252:100-43 (Testing, Monitoring, and Recordkeeping) [Applicable]
This subchapter provides general requirements for testing, monitoring and recordkeeping and applies to any testing, monitoring or recordkeeping activity conducted at any stationary source. To determine compliance with emissions limitations or standards, the Air Quality Director may require the owner or operator of any source in the state of Oklahoma to install, maintain and operate monitoring equipment or to conduct tests, including stack tests, of the air contaminant source. All required testing must be conducted by methods approved by the Air Quality Director and under the direction of qualified personnel. A notice-of-intent to test and a testing protocol shall be submitted to Air Quality at least 30 days prior to any EPA Reference Method stack tests. Emissions and other data required to demonstrate compliance with any federal or state emission limit or

standard, or any requirement set forth in a valid permit shall be recorded, maintained, and submitted as required by this subchapter, an applicable rule, or permit requirement. Data from any required testing or monitoring not conducted in accordance with the provisions of this subchapter shall be considered invalid. Nothing shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

The following Oklahoma Air Pollution Control Rules are not applicable to this facility:

OAC 252:100-7	Permit for Minor Facilities	not in source category
OAC 252:100-11	Alternative Emissions Reduction	not requested
OAC 252:100-15	Mobile Sources	not in source category
OAC 252:100-23	Cotton Gins	not type of EU
OAC 252:100-24	Grain Elevators	not in source category
OAC 252:100-39	Nonattainment Areas	not in area category
OAC 252:100-47	Existing Municipal Solid Waste Landfills	not in source category

SECTION VIII. FEDERAL REGULATIONS

PSD, 40 CFR Part 52 [Applicable]

Total potential emissions of NO_X, CO, VOC, SO_2, PM_{10}, $PM_{2.5}$, and CO_{2e} are greater than the major source threshold of 100 TPY and 100,000 TPY, respectively. Any future increases of emissions must be evaluated for PSD if they exceed a significance level (40 TPY NO_X, 100 TPY CO, 40 TPY VOC, 40 TPY SO_2, 25 TPY PM, 15 TPY PM_{10}, 10 TPY $PM_{2.5}$, 75,000 TPY CO_{2e}).

NSPS, 40 CFR Part 60

[Subparts A, Db, Dc, J, Ja, Kb, GGG, GGGa, QQQ, IIII, and JJJJ are Applicable]

Due to the overlap Provisions of NESHAP, Subparts CC, UUU, and LLLLL, specific equipment is exempted from complying with NSPS, Subparts K, Ka, Kb, UU, XX, GGG, GGGa, and QQQ.

Subpart A, General Provisions. This subpart contains requirements for control devices used to comply with applicable subparts of Part 60 that specifically refer to this subpart. The following flares are subject to these requirements.

EU	Point	Description	Mod. Date
HI-81003	P58	East Flare	1976
HI-81001	P59	West Flare	1993

The LPLT Vapor Combustor is used to comply with NESHAP, Subpart R which requires compliance with some of the requirements of NSPS, Subpart XX. However, the vapor combustor has to comply with the requirements of NESHAP, Subpart A.

Subparts D and Da, Fossil Fired Steam Generators. These subparts affect any fossil-fuel-fired steam generating unit with a heat input rate of 250 MMBTUH. Only one EU that was constructed prior to June 19, 1984, exceeds 250 MMBUTH and it is not considered a steam generator.

EU	Description Heaters	Rating MMBTUH	Const. Date
H-15001	Process Heater	326.8	1992

Subpart Db, Industrial-Commercial-Institutional Steam Generating Units. This subpart affects steam generating units with a heat input capacity greater than 100 MMBTUH and that commenced construction, modification, or reconstruction after June 19, 1984. All of the units greater than 100 MMBTUH are shown in the table below.

EU	Description Boilers	Rating MMBTUH	Const. Date
B-253A	Boiler/CO Boiler	144.0	2004-5
B-253B	Boiler/CO Boiler	144.0	2004-5
B-15001	Boiler	285.3	2015
EU	**Heaters**	**MMBTUH**	**Date**
H-102A	Process Heater	160.0	1998
H-102B	Process Heater	135.0	1998
H-103	Process Heater	102.6	1974
H-201	Process Heater	116.7	1974
H-603	Process Heater	125.5	1992
H-15001	Process Heater	326.8	1992

Most of the EU meet the definition of process heaters and are not affected units. Process heater means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst. Both of the listed CO boilers (B-253A and B-253B) and the steam boiler (B-15001) are subject to this subpart.

Boiler B-15001

Boiler B-15001 fires only refinery gas and natural gas. This is significant, in terms of regulatory applicability, because §60.40b(b)(1) through (4) include requirements specific to boilers which fire coal and/or oil. Because boiler B-15001 fires neither coal nor oil, the requirements identified in these subparagraphs (including the requirement to comply with SO_2 standards under Subpart D) do not apply to the new unit. In accordance with §60.40b(c), because the unit is subject to SO_2 standards under NSPS, Subpart Ja, the unit must comply with those requirements as well as applicable PM and NO_X standards under this subpart. Because the unit will not fire coal, oil, wood, or municipal solid waste, it is not subject to any PM standards included in §60.43b. Manufacturer's data confirm that the new boiler will exhibit a *low heat release rate* as defined in §60.42b (≤ 70,000 Btu/hr•ft^3); the heat release rate is the "steam generating unit design heat input capacity (in MW or Btu/hr) divided by the furnace volume…" Under this subpart, the boiler is subject to standards for nitrogen oxides (NO_X) applicable to units which fire natural gas or refinery gas. When firing natural gas, the new boiler is subject to the NO_X limits (expressed as NO_2) presented in §60.44b of this subpart: 0.10 lb/MMBtu (30-day rolling average). The refinery gas that is also used to fuel the boiler does not meet the definition of *natural gas* in this subpart, because it will contain less than 70% methane and the gross caloric value of the refinery gas will likely be less than 910 Btu per dry scf. However, the refinery gas does meet the definition of *byproduct/waste*: "any liquid or gaseous substance produced at chemical manufacturing plants, petroleum refineries, or pulp and paper mills (except natural gas, distillate oil, or residual oil) and combusted in a steam generating unit for heat recovery or for disposal. Gaseous substances with carbon dioxide (CO_2) levels greater than 50 percent or carbon monoxide levels greater than 10 percent are not byproduct/waste for the purpose of this subpart." As such, the new boiler is still required to meet a NO_X standard (expressed as NO_2) of 0.10 lb/MMBtu (30-day rolling average) in accordance with §60.44b(e). The applicant has elected to install a continuous emissions monitoring system (CEMS) to monitor compliance with these requirements. All applicable requirements have been incorporated into the permit.

<u>CO Boilers B-253A and B-253B</u>

Affected facilities that also meet the applicability requirements under subpart J or subpart Ja of this part are subject to the PM and NO_X standards under this subpart and the SO_2 standards under subpart J or subpart Ja of this part, as applicable. Therefore, the CO boilers would only be subject to the PM and NO_X standards of this subpart. However, the PM emission standards only apply to affected facilities that combust coal, oil, wood, municipal-type solid waste or mixtures of these fuels with any other fuels. The CO boilers do not combust these types of fuel.

With regard to the CO boilers (B-253A and B-253B), the NO_X emission limit is not subject to affected facilities with heat inputs less than 250 MMBTUH that meet the following requirements:

1. Combust, alone or in combination, only natural gas, distillate oil, or residual oil with a nitrogen content of 0.30% by weight or less;
2. Have a combined annual capacity factor of 10% or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30% by weight or less; and
3. Are subject to a federally enforceable requirement limiting operation of the affected facility to the firing of natural gas, distillate oil, and/or residual oil with a nitrogen content of 0.30% by weight or less and limiting operation of the affected facility to a combined annual capacity factor of 10% or less for natural gas, distillate oil, and residual oil with a nitrogen content of 0.30% by weight or less.

The CO boilers are subject to an annual capacity factor of 10% or less of natural gas, distillate fuel oil, and residual oil with a nitrogen content of 0.30 weight percent or less and are not subject to the NO_X emission limits of this subpart.

The CO boilers are only subject to the recordkeeping requirements of this subpart. All applicable requirements have been incorporated into the permit.

<u>Subpart Dc</u>, Small Industrial-Commercial-Institutional Steam Generating Units. This subpart affects steam generating units with a heat input capacity between 10 and 100 MMBTUH and that commence construction, modification, or reconstruction after June 9, 1989. All of the units less than 100 MMBTUH are shown in the table below.

EU	Description Boilers/Heaters	Rating MMBTUH	Const./Mod. Date
B-801	Boiler	72.5	1974
B-802	Boiler	89.8	1975
B-803	Boiler	86.8	1979
H-101	Process Heater	30.8	1998
H-301	Process Heater	21.6	1974
H-401A	Process Heater	16.0	1969
H-401B	Process Heater	14.8	1974
H-402A	Process Heater	13.9	1970
H-402B	Process Heater	15.8	1963
H-403	Process Heater	98.7	1980
H-404/5	Process Heater	99.3	1980
H-406	Process Heater	28.0	1974
H-411	Process Heater	28.0	1986
H-601	Process Heater	58.5	1975
H-901	Process Heater	60.0	1969
H-1016	Process Heater	4.8	1954
H-2601	Process Heater	13.2	2014
H-5602	Hot Oil Heater	20.0	2004
H-6501	Process Heater	99.7	1992/2008
H-6502	Process Heater	54.3	1992
H-6701	Co-Processor Heater	11.8	2004
H-100024	Asphalt Tank Heater	13.5	1999
H-210001	Asphalt Tank Heater	12.2	1996

Most of the EUs meet the definition of process heaters and/or were constructed prior to the applicability date and are not affected units. Steam generating unit means a device that combusts any fuel and produces steam or heats water or any other heat transfer medium. The Hot Oil Heater (H-5602) and Asphalt Tank Heaters (H-100024 and H-210001) are considered steam generating units since they heat oil, which is then used to transfer heat to other materials, and are subject to this subpart. All applicable requirements have been incorporated into the permit. These EU are only subject to the fuel recordkeeping requirement of this subpart since they do not combust coal, wood, oil and/or a mixture of these fuels. Per 40 CFR 60.48(g) the owner/operator of each affected EU will be required to record and maintain records of the amounts of each fuel combusted during each month since the potential SO_2 emissions rate of refinery fuel gas is typically below 0.32 lb/MMBTU (~1,516 ppmv H_2S & ~0.95 gr H_2S/DSCF @ 800 BTU/SCF).

Subpart I, Hot Mix Asphalt Facilities. This facility does not manufacture hot mix asphalt by heating and drying aggregate and mixing with asphalt cements. This facility only manufactures asphalt cements.

Subpart J, Petroleum Refineries. This subpart applies to the following affected facilities in petroleum refineries: fuel gas combustion devices, FCCU catalyst regenerators, and Claus sulfur recovery plants.

Fuel Gas Combustion Devices

Fuel gas combustion device means any equipment, such as process heaters, boilers and flares used to combust fuel gas, except facilities in which gases are combusted to produce sulfur or sulfuric acid. Fuel gas means any gas which is generated at a petroleum refinery and which is combusted. Fuel gas also includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Fuel gas does not include gases generated by catalytic cracking unit catalyst regenerators and fluid coking burners. All fuel gas combustion devices which commence construction or modification after June 11, 1973, are subject to a fuel gas H_2S limitation of 0.10 grains of H_2S/DSCF which is required to be continuously monitored and recorded. All of the heaters and boilers are considered refinery fuel gas combustion devices. The heaters and boilers subject to this subpart based on the date of construction or modification are listed in the following table.

	Description	**Rating**	**Const./Mod.[1]**
EU	**Boilers/Heaters**	**MMBTUH**	**Date**
B-801	Boiler	72.5	1974
B-802	Boiler	89.8	1977
B-803	Boiler	86.8	1979
B-253A	CO Boiler	144.0	2004
B-253B	Boiler/CO Boiler	144.0	2004
H-101	Process Heater	30.8	1998
H-102A	Process Heater	160.0	1998
H-102B	Process Heater	135.0	1998
H-103	Process Heater	102.6	1974
H-201	Process Heater	116.7	1974
H-301	Process Heater	21.6	1974
H-401A	Process Heater	16.0	1969
H-401B	Process Heater	14.8	1974
H-402A	Process Heater	13.9	1970
H-402B	Process Heater	15.8	1963
H-403	Process Heater	98.7	1980
H-404/5	Process Heater	99.3	1980
H-406	Process Heater	28.0	1985
H-411	Process Heater	28.0	1986
H-601	Process Heater	58.5	1975
H-603	Process Heater	125.5	1992
H-901	Process Heater	60.0	1969
H-1016	Process Heater	4.8	1954
H-5602	Hot Oil Heater	20.0	2004
H-6701	Co-Processor Heater	11.8	2004
H-6502	Process Heater	54.3	1992
H-15001	Process Heater	326.8	1992
H-100024	Asphalt Tank Heater	13.5	1999
H-210001	Asphalt Tank Heater	12.2	1996

[1] – Some EU became subject to NSPS, Subpart J as a result of the global consent order.

The CO boilers are affected units but only due to the supplemental refinery fuel gas they combust. Fuel gas combusted by the affected units must be monitored and recorded and can be done at one location. Based on 2012 monitoring data, the typical sulfur content of the refinery fuel gas used at the Valero Refinery is 38 ppmv or 0.024 grains of H_2S/DSCF.

The flares and thermal oxidizers listed in the following table are also considered fuel gas combustion devices and are also subject to the fuel gas sulfur content limitation.

EU	Description	Const./Mod. Date
HI-801	Asphalt Blowstill Incinerator	1992
HI-13001	LPLT Vapor Combustor	1996
HI-8801	WWTP Incinerator	2004

Alternative monitoring plans (AMPs) for the following units have been submitted. Items 1 through 6 have been approved by EPA and/or the AQD. Schedule(s) of Compliance were submitted for items 7, 8, and 9 and were incorporated into the Specific Conditions of the permit. The AMP for item 10 was modified as requested by Valero and approved by EPA with confirmation testing performed on December 13-14, 2016. The specific conditions have incorporated these changes.

1. CCR Catalyst Disengagement Purge Gas System (HI-81001, H-404 and H-405);
2. CCR Catalyst Regeneration Purge Gas System (H-404 and H-405);
3. Tank Truck Loading Dock Vapors (LPLT);
4. Isomerization Unit Desiccant Dryers Purge Vapors (HI-81001);
5. Pressure Swing Absorption (PSA) Off-Gas System (H-15001);
6. H_2S and CO draegers for use during CEM downtime (AQD).
7. Molten sulfur storage tank T-5602 routed to incinerator HI-5602;
8. #1 SRU molten sulfur storage pit routed to incinerator HI-501;
9. MEROX disulfide settler off gas routed to incinerator HI-801 or HI-501; and
10. FCC Flue Gas Scrubber (FGS-200)

<u>CCR Catalyst Disengagement & Regeneration Purge Gas Systems</u>
Daily monitoring of the H_2S content of the H_2 feed to the reformer unit using Draeger tubes and the reformer feedstock and reformer product sulfur concentration using ASTM 2622 with semi-annual submission of the data was accepted by the EPA. If the feedstock or product sulfur content exceeds 81 ppm, the purge gas streams to HI-81001, H-404, and H-405 must be monitored daily and approval of the AMP is considered withdrawn.

<u>Tank Truck Loading Dock Vapors</u>
The submittal satisfied the one time monitoring requirement for this type of fuel gas combustion device and no additional monitoring was required.

<u>Isomerization Unit Desiccant Dryers Purge Vapors</u>
Daily monitoring of the H_2S content of the Isomerization Unit dessicant dryer using Draeger tubes with semi-annual submission of the data was accepted by the EPA.

PSA Off-Gas System
Daily monitoring of the H_2S content from the outlet of the zinc oxide bed of the PSA off gas system using Draeger tubes with semi-annual submission of the data was accepted by the EPA.

If the gas stream compositions of the submitted AMPs change the approval of the AMPs are considered withdrawn and must be resubmitted for approval.

FCCU Catalyst Regenerators
All FCCU catalyst regenerators that commence construction or modification after June 11, 1973, are subject to the following limitations:

1. A PM emission limitation of 1.0 lb/1,000 lbs of coke burn-off, which is required to be continuously monitored and recorded (when exhaust gases discharged from the FCCU are combusted by a waste heat boiler in which supplemental liquid or solid fuel is burned PM in excess of this limit may be emitted which shall not exceed 0.1 lb/MMBTU of heat input);
2. A 30% opacity limitation, except for one six-minute average opacity reading in any one hour period;
3. A CO emission limitation of 500 ppmdv, which is required to be continuously monitored and recorded; and
4. One of the following SO_2 emission limitations:
   a) For units with an add-on control device, a requirement to reduce SO_2 emissions by 90% or to maintain SO_2 emissions to less than 50 ppmv, whichever is less stringent;
   b) For units without an add-on control device, an SO_2 emission limitation of 9.8 lbs/1,000 lbs of coke burn-off; or
   c) A limit of the 0.30 percent by weight or less sulfur in the FCCU fresh feed.

   Compliance with these limits must be determined based on continuous monitoring and a seven day rolling average.

FCCU catalyst regenerators that commenced construction or modification prior to January 17, 1984, are exempt from the SO_2 emission limit. The FCCU was modified after 1984 and is subject to this entire subpart. All applicable requirements for the FCCU Regenerators have been incorporated into the permit. The Platformer CCR is considered a catalytic reforming unit and is not subject to this subpart.

Claus Sulfur Recovery Plants
For Claus sulfur recovery plants with an oxidation control system or a reduction control system followed by incineration, Subpart J limits SO_2 emissions to 250 ppmvd at 0% excess air. The SRUs are subject to this emission limit, continuous emission monitoring, and the recordkeeping and reporting requirements of this subpart. All applicable requirements have been incorporated into the permit.

Subpart Ja, Petroleum Refineries. This subpart applies to the following affected facilities in petroleum refineries: FCCU, fluid coking units (FCU), delayed coking units, fuel gas combustion devices, including flares and process heaters, and sulfur recovery plants. Except for flares and delayed coking units, this subpart only applies to those affected facilities that began construction, modification, or reconstruction after May 14, 2007. For flares this subpart only applies to flares which commence construction, modification or reconstruction after June 24, 2008.

The following special provisions supersede the provisions in § 60.14 with respect to flares. A modification to a flare occurs as provided below:

1. Any new piping from a refinery process unit, including ancillary equipment, or a fuel gas system is physically connected to the flare except for the following:
   i. Connections made to install monitoring systems to the flare.
   ii. Connections made to install a flare gas recovery system or connections made to upgrade or enhance components of a flare gas recovery system.
   iii. Connections made to replace or upgrade existing pressure relief or safety valves, provided the new pressure relief or safety valve has a set point opening pressure no lower and an internal diameter no greater than the existing equipment being replaced or upgraded.
   iv. Connections made for flare gas sulfur removal.
   v. Connections made to install back-up (redundant) equipment associated with the flare (such as a back-up compressor) that does not increase the capacity of the flare.
   vi. Replacing piping or moving an existing connection from a refinery process unit to a new location in the same flare, provided the new pipe diameter is less than or equal to the diameter of the pipe/connection being replaced/moved.
   vii. Connections that interconnect two or more flares.
2. A flare is physically altered to increase the flow capacity of the flare.

Fuel Gas Combustion Devices

Fuel gas combustion device means any equipment, such as process heaters, boilers and flares used to combust fuel gas, except facilities in which gases are combusted to produce sulfur or sulfuric acid. The HDS Reactor Heater H-2601 and boiler B-15001 are subject to this subpart. All applicable requirements have been incorporated into the permit.

EU	Description	MMBTUH	Const. Date
B-15001	Boiler	285.3	2015
H-2601	HDS Reactor Heater	13.2	2014

Based on the current rule, all of the flares have been or will be modified after June 24, 2008. All applicable requirements have been incorporated into the permit.

EU	Description	Mod. Date
HI-81001	West flare	2009
HI-81002	HF Process Gas Flare	2010
HI-81003	East Flare	2009

The facility was required to develop and submit a flare management plan in accordance with § 60.103a(a) and (b). If the following flare is placed back into service, it would immediately become applicable to this subpart.

EU	Point	Description	Mod. Date
HI-81004	P81	Backup East Flare – 16” SASFF	To Be Determined

This subpart establishes a fuel gas H_2S limitation for all fuel gas combustion devices which commence construction, reconstruction, or modification after May 14, 2007, of 162 ppmv determined hourly on a 3-hour rolling average basis and 60 ppmv determined daily on a 365 successive calendar day rolling average basis. Subpart Ja requires the fuel gas H_2S concentration to be continuously monitored and recorded. (It should be noted that a fuel gas CEMS is already in operation at the facility.) In addition, §60.103a(c)(2) requires the permittee to report excess SO_2 emissions which are, essentially, emissions ≥ 500 lb more than allowable if the fuel gas H_2S concentration limits were abided by. If the facility experiences such an excess emission event, it is required to perform a root cause analysis and perform corrective actions. All applicable requirements have been incorporated into the permit.

This subpart also establishes NO_X emissions limits for process heaters with a rated capacity greater than 40 MMBTUH (HHV) which commence construction, reconstruction, or modification after May 14, 2007. For natural draft process heaters either:

1. 40 ppmdv @ 0% excess air determined daily on a 30-day rolling average basis; or
2. 0.040 lb/MMBTU (HHV) determined daily on a 30-day rolling average basis.

For forced draft process heaters either:

1. 60 ppmdv @ 0% excess air determined daily on a 30-day rolling average basis; or
2. 0.060 lb/MMBTU (HHV) determined daily on a 30-day rolling average basis.

If fuel gas composition is not monitored as specified in § 60.107a(d), the owner or operator must comply with the concentration limits. Additional limits are established for co-fired (gaseous and liquid fuel fired) process heaters but this facility does not utilize co-fired process heaters.

H-6501 was modified but only with respect to SO_2 emissions. The modification did not result in an increase in NO_X emissions. Therefore, the heater is not subject to the NO_X emission limits.

	Description	Rating	Const./Mod.
EU	Heaters	MMBTUH	Date
H-6501	Process Heater	99.7	Mod. 2008

Boiler B-15001 meets the definition of *fuel gas combustion device* and it is subject to requirements applicable to such units. As mentioned previously, this subpart establishes NO_X emission limits for units which also meet the definition of *process heater* and which have a rated capacity greater than 40 MMBTUH. This subpart defines *process heater* as “an enclosed combustion device used to transfer heat indirectly to process stream materials (liquids, gases, or solids) or to a heat transfer material for use in a process unit instead of steam.” Boiler B-15001 does not meet this definition, because it does not transfer heat to process stream materials; rather, it is used to produce steam. Therefore, it is not be subject to the NO_X emission limits under this subpart.

All applicable requirements have been incorporated into the permit.

Emergency generator EG1880-01 is only fueled with commercial natural gas, it is not a "fuel gas combustion device" as defined by this subpart and is not subject to this subpart.

FCCU & Sulfur Recovery Plants
Fluid catalytic cracking unit means a refinery process unit in which petroleum derivatives are continuously charged and hydrocarbon molecules in the presence of a catalyst suspended in a fluidized bed are fractured into smaller molecules, or react with a contact material suspended in a fluidized bed to improve feedstock quality for additional processing and the catalyst or contact material is continuously regenerated by burning off coke and other deposits. The unit includes the riser, reactor, regenerator, air blowers, spent catalyst or contact material stripper, catalyst or contact material recovery equipment, and regenerator equipment for controlling air pollutant emissions and for heat recovery. When fluid catalyst cracking unit regenerator exhaust from two separate fluid catalytic cracking units share a common exhaust treatment (e.g., CO boiler or wet scrubber), the fluid catalytic cracking unit is a single affected facility.

Sulfur recovery plant means all process units which recover sulfur from H_2S and/or SO_2 from a common source of sour gas produced at a petroleum refinery. The sulfur recovery plant also includes sulfur pits used to store the recovered sulfur product, but it does not include secondary sulfur storage vessels or loading facilities downstream of the sulfur pits. Multiple sulfur recovery units are a single affected facility only when the units share the same source of sour gas. Sulfur recovery plants that receive source gas from completely segregated sour gas treatment systems are separate affected facilities.

The FCCU and Sulfur Recovery Plants were constructed prior to May 14, 2007, and have not been reconstructed or modified after May 14, 2007.

Subpart K, Storage Vessels for Petroleum Liquids. This subpart affects storage vessels of petroleum liquids which have a storage capacity greater than 40,000 gallons but less than 65,000 gallons and which commenced construction, reconstruction, or modification after March 8, 1974, or which have a capacity greater than 65,000 gallons and which commenced construction, reconstruction, or modification after June 11, 1973, but prior to May 19, 1978. The table below lists all storage vessels constructed, reconstructed, or modified between these dates and applicable capacities.

EU	Roof Type	Contents	Barrels	VP Psia	Const. Date
T-1082	External Floating	Crude Oil	124,714	≤ 11.1	1974
T-1083	External Floating	Crude Oil	124,714	≤ 11.1	1974
T-1102	Cone	Asphalt/Gas Oil	75,786	<1.5	1975
T-1125	External Floating	Gasoline	124,398	≤ 11.1	1974
T-1126	External Floating	Gasoline	124,412	≤ 11.1	1974
T-1127	Cone	Diesel/Jet Fuel	80,579	<1.5	1974
T-1129	Cone	Diesel/Jet Fuel	2,113	<1.5	1975

Petroleum liquids do not include Nos. 2 through 6 fuel oils, gas turbine fuel oils Nos. 2–GT through 4–GT, or diesel fuel oils Nos. 2–D and 4–D. The diesel/jet fuel storage vessels store these types of fuel oils and are not subject to this subpart. Also, any storage vessels storing petroleum liquids with a true vapor pressure less than 1.5 psia do not have to meet the control requirements of this subpart. This would include the asphalt/gas oil and LCO slurry storage vessels. Therefore, only storage vessels T-1082, T-1083, T-1125, and T-1126 would be subject to the control requirements of this subpart.

The overlap requirements of NESHAP, Subpart CC states that any Group 1 storage vessel subject to the provisions of NSPS, Subpart K and NESHAP, Subpart CC is only required to comply with NESHAP, Subpart CC. The overlap requirements of NESHAP, Subpart CC also states that any Group 2 storage vessel subject to the control requirements of NSPS, Subpart K and NESHAP, Subpart CC is only required to comply with NSPS, Subpart K except as provided in § 63.640(n)(9). However, Group 2 storage vessels not subject to the control requirements of NSPS Subpart K only have to comply with NESHAP, Subpart CC.

All of the storage vessels “associated with petroleum refining process units” and “associated with a bulk gasoline terminal” listed above are subject to NESHAP, Subpart CC. Therefore, the following storage vessels are only subject to NESHAP, Subpart CC.

EU	Roof Type	Contents	Barrels	VP Psia	Const. Date
T-1082	External Floating	Crude Oil	124,714	≤ 11.1	1974
T-1083	External Floating	Crude Oil	124,714	≤ 11.1	1974
T-1125	External Floating	Gasoline	124,398	≤ 11.1	1974
T-1126	External Floating	Gasoline	124,412	≤ 11.1	1974
T-1127	Cone	Diesel/Kerosene	80,579	<1.5	1974
T-1129	Cone	Diesel/Kerosene	2,113	<1.5	1975

The asphalt storage vessel listed below is associated with an asphalt processing facility and is subject to NESHAP, Subpart LLLLL.

EU	Roof Type	Contents	Barrels	VP Psia	Const. Date
T-1102	Cone	Asphalt	75,786	<1.5	1975

The following table shows all storage vessels constructed prior to NSPS, Subpart K.

EU	Roof Type	Contents	Barrels	VP Psia	Const. Date
T-1019	External Floating	Alkylate & Gasoline	66,868	≤ 11.1	1948
T-1113	Cone	Gas Oil/Asphalt	131,005	<1.5	1959
T-1115	External Floating	Gasoline W/Ethanol	27,205	≤ 11.1	1953
T-1116	External Floating	Gasoline W/Ethanol	27,315	≤ 11.1	1953
T-1123	External Floating	Gasoline/Diesel	60,766	≤ 11.1	1968
T-1124	External Floating	Gasoline	111,721	≤ 11.1	1972
V-815	Cone	Wastewater Centrifuge Solids	1,731	<1.5	1968

All of these storage vessels (shown in the table above) except for the asphalt and PMA storage vessels (which are subject to NESHAP, Subpart LLLLL) are subject to NESHAP, Subpart CC.

Subpart Ka, Storage Vessels for Petroleum Liquids. This subpart affects storage vessels for petroleum liquids that have a storage capacity greater than 40,000 gallons and which commenced construction, reconstruction, or modification after May 18, 1978, and prior to July 23, 1984.

EU	Roof Type	Contents	Barrels	VP Psia	Const. Date
T-1084	External Floating	Crude Oil	124,714	≤ 11.1	1978
T-1130	External Floating	Gasoline	79,414	≤ 11.1	1978
T-1131	External Floating	Gasoline/FCCU Gasoline/ ISOM/Hydrocracker Naptha	125,100	≤ 11.1	1979
T-1132	External Floating	Reformate	80,138	≤ 11.1	1979

Any storage vessels storing petroleum liquids with a true vapor pressure less than 1.5 psia do not have to meet the control requirements of this subpart. All of the other storage vessels are subject to the control requirements of this subpart.

The overlap requirements of NESHAP, Subpart CC states that any Group 1 storage vessel subject to the provisions of NSPS, Subpart Ka and NESHAP, Subpart CC is only required to comply with NESHAP, Subpart CC. The overlap requirements of NESHAP, Subpart CC also states that any Group 2 storage vessel subject to the control requirements of NSPS, Subpart Ka and NESHAP, Subpart CC is only required to comply with NSPS, Subpart Ka except as provided in § 63.640(n)(9). However, Group 2 storage vessels not subject to the control requirements of NSPS Subpart Ka only have to comply with NESHAP, Subpart CC.

All of the listed tanks are considered Group 1 storage vessels and only have to comply with NESHAP, Subpart CC.

Subpart Kb, VOL Storage Vessels. This subpart affects storage vessels for VOL that have a storage capacity greater than 19,813 gallons and which commenced construction, reconstruction, or modification after July 23, 1984. The following storage vessels are only required to keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel:

- Storage vessels with a capacity greater than or equal to 39,890 gallons that store a liquid with a maximum true vapor pressure less than 0.5076 psia; or
- Storage vessels with a capacity greater than or equal to 19,813 but less than 39,890 gallons that store a liquid with a maximum true vapor pressure less than 2.1756 psia.

In addition to records of capacity, the following storage vessels are also only required to maintain a record of the VOL stored, the period of storage, and the maximum true vapor pressure of that VOL during the respective storage period:

- Storage vessels with a capacity greater than or equal to 39,890 gallons that store a liquid with a maximum true vapor pressure less than 0.7542 psia; or
- Storage vessels with a capacity greater than or equal to 19,813 but less than 39,890 gallons that store a liquid with a maximum true vapor pressure less than 4.0031 psia.

The table below lists all of the VOL storage vessels constructed after July 23, 1984, with a capacity greater than 19,813 gallons.

Storage Vessel	Roof	Contents	Barrels	VP Psia	Const. Date
T-153	CR	FCCU Charge	200,676	<0.5	2003
T-156	CR	FCCU Slurry	56,000	<0.5	2003
T-1018R	EFR	Alkylate & Gasoline	62,850	≤ 11.1	2018
T-1118	CR	Asphalt	79,742	<0.5	2012
T-1121	Cone	Diesel/Kerosene	40,526	<0.5	2012
T-1128	CR	Diesel/Jet Fuel	80,574	< 0.5	2011
T-1141	CR	Diesel/Kerosene	119,189	<0.5	1992
T-1142	CR	Diesel/Kerosene	79,445	<0.5	1992
T-1151	CR	Asphalt	206,979	<0.5	1998
T-1152	EFR	Sour Water	11,890	<11.1	1999
T-1155	EFR	Heavy Naphtha/Distillate	163,555	<11.1	2003
T-5801	CR	Amine	895	<2.2	2004-5
T-83001	CR	Sour Water Stripper Feed	18,885	<0.5	1993
T-100149	CR	Asphalt Flux	35,847	<0.5	1996
T-100150	CR	Asphalt Base	35,847	<0.5	1996
T-210003	CR	Asphalt Flux	3,021	<0.5	1996
T-210004	CR	PMA Rxn	6,526	<0.5	1996
T-210005	CR	PMA Rxn	6,526	<0.5	1996
T-210006	CR	PMA	10,197	<0.5	1996
T-210007	CR	PMA	10,197	<0.5	1996
T-210008	CR	PMA	11,715	<0.5	2001
T-100160	CR W/IFR	Ethanol	14,000	≥ 0.75	2010
TK-90002	Cone	Acid Soluble Oil (ASO)	630	<0.5	2008

The definition of storage vessel under this subpart does not include process tanks which are defined as tanks that are used within a process (including a solvent or raw material recovery process) to collect material discharged from a feedstock storage vessel or equipment within the process before the material is transferred to other equipment within the process, to a product or by-product storage vessel, or to a vessel used to store recovered solvent or raw material. In many process tanks, unit operations such as reactions and blending are conducted. Other process tanks, such as surge control vessels and bottoms receivers, however, may not involve unit operations. Oil-Water Separators are considered process tanks because they are used to separate the water and oil in the wastewater stream (a unit operation) and the recovered oil (a raw material) is then transferred to another tank for storage before being sent back through the refining process.

Most of the storage vessels do not store a VOL with a vapor pressure greater than 0.5 psia and are only subject to the requirement to keep for the life of the storage vessel records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel.

The sour water, naphtha/diesel, and ethanol storage vessels (T-1152, T-1155, & T-100160) are subject to the control requirements of this subpart.

The overlap requirements of NESHAP, Subpart CC states that any Group 1 or Group 2 storage vessel at an existing source subject to the provisions of NSPS, Subpart Kb and NESHAP, Subpart CC is only required to comply with NSPS, Subpart Kb except as provided in § 63.640(n)(8)(i) through (iv).

Since NSPS, Subpart QQQ states that a storage vessel subject to the standards in § 60.112b and associated requirements is not subject to the requirements of § 60.692-3. T-1152 is subject to the control requirements of § 60.112b. All applicable requirements have been incorporated into the permit.

Subpart UU, Asphalt Processing and Asphalt Roofing Manufacture. This subpart affects each asphalt storage vessel and each blowing still at petroleum refineries. Asphalt storage vessels and blowing stills that process and/or store asphalt used for roofing and other purposes and that commenced construction or modification after November 18, 1980, are subject to the requirements of this subpart. Asphalt storage vessels and blowing stills that process and/or store only non-roofing asphalt and that commenced construction or modification after May 26, 1981, are also subject to the requirements of this subpart. The Asphalt Blowstill was altered in 1992. However, since only the blowstill thermal oxidizer was replaced and no increase in emissions resulted from the project, the modification was not considered a modification under NSPS. Therefore, the Asphalt Blowstill is not subject to the requirements of this subpart.

EU	Description
HI-801	Asphalt Blowstill and Thermal Oxidizer

Asphalt storage vessels constructed after May 26, 1981, are listed in the following table.

Storage Vessel	Roof Type	Contents	Barrels	VP Psia	Const. Date
T-1151	Cone	Asphalt	206,979	<0.5	1998
T-210003	Cone	Asphalt Flux	3,021	<0.5	1996
T-210004	Cone	PMA Rxn	6,526	<0.5	1996
T-210005	Cone	PMA Rxn	6,526	<0.5	1996
T-210006	Cone	PMA	10,197	<0.5	1996
T-210007	Cone	PMA	10,197	<0.5	1996
T-210008	Cone	PMA	11,715	<0.5	2001
T-100149	Cone	Asphalt Flux	35,847	<0.5	1996
T-100150	Cone	Asphalt Base	35,847	<0.5	1996
T-1118	CR	Asphalt	79,742	<0.5	2012

This subpart limits the opacity from asphalt storage tanks to 0 percent, except for one consecutive 15-minute period in any 24-hour period when the transfer lines are being blown for clearing. Method 9 and the procedures in §60.11 are required to determine the opacity.

Due to the overlap provisions of NESHAP, Subpart LLLLL, existing sources subject to this subpart are only required to comply with the NESHAP after May 1, 2006. Therefore, all of the tanks are now only subject to NESHAP, Subpart LLLLL.

<u>Subpart VV</u>, Equipment Leaks of VOC in the Synthetic Organic Chemical Manufacturing Industry (SOMCI). This subpart affects equipment constructed, reconstructed or modified after January 5, 1981 and on or before November 7, 2006. NSPS, Subpart GGG requires equipment constructed, reconstructed or modified after January 5, 1981 and prior to November 7, 2006 in VOC service to comply with paragraphs §§ 60.482-1 through 60.482-10, 60.484, 60.485, 60.486, and 60.487 except as provided in § 60.593. All equipment in VOC service affected under this permit is subject to NSPS, Subpart GGG or NESHAP Subpart CC.

<u>Subpart VVa</u>, Equipment Leaks of VOC in the Synthetic Organic Chemical Manufacturing Industry (SOMCI). This subpart affects equipment constructed, reconstructed or modified after November 7, 2006. NSPS, Subpart GGGa requires equipment constructed, reconstructed or modified after November 7, 2006 in VOC service to comply with paragraphs §§ 60.482-1a through 60.482-10a, 60.484a, 60.485a, 60.486a, and 60.487a except as provided in § 60.593a. Most of the equipment was constructed prior to November 7, 2007 and is covered under NSPS, Subpart GGG or NESHAP Subpart CC.

<u>Subpart XX</u>, Bulk Gasoline Terminals. This subpart affects loading racks at bulk gasoline terminals which deliver liquid product into gasoline tank trucks and that commenced construction or modification after December 17, 1980. The light products loading terminal at the refinery was built prior to the applicable effective date of this subpart and was later modified to comply with NESHAP, Subpart CC. The new VOC railcar loading rack is subject to NESHAP, Subpart CC. Due to the overlap requirements of NESHAP, Subpart CC and since these are Group 1 loading racks, the loading racks are only subject to NESHAP, Subpart CC.

<u>Subpart GGG</u>, Equipment Leaks of VOC in Petroleum Refineries. This subpart affects each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service at a process unit, which commenced construction or modification after January 4, 1983 and on or before November 7, 2006, and which is located at a petroleum refinery. This subpart defines "process unit" as "components assembled to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates: a process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product." Subpart GGG requires the leak detection, repair, and documentation procedures of NSPS, Subpart VV. All affected equipment which commenced construction or modification after January 4, 1983 and prior to November 7, 2006 in VOC service and not in HAP service is subject to this subpart. After the effective date of 40 CFR Part 63 NESHAP, Subpart CC, (August 18, 1998), all equipment in organic HAP service is subject only to Subpart CC, which also requires compliance with NSPS, Subpart VV. All applicable requirements have been incorporated into this permit.

Subpart GGGa, Equipment Leaks of VOC in Petroleum Refineries. This subpart affects each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service at a process unit, which commenced construction or modification after November 7, 2006, and which is located at a petroleum refinery. This subpart defines "process unit" as "components assembled to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates: a process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product." Subpart GGGa requires the leak detection, repair, and documentation procedures of NSPS, Subpart VVa. All affected equipment which commenced construction or modification after November 7, 2006, is subject to this subpart. As stated in the overlap provisions of NESHAP Subpart CC, equipment leaks that are subject to the provisions of NESHAP, Subpart CC and NSPS, Subpart GGGa are only required to comply with the provisions of NSPS, Subpart GGGa. All applicable requirements have been incorporated into this permit.

The refinery will incorporate new fugitive equipment into the existing LDAR program upon installation. PRV emissions will be routed to the flare system. Compressor seal(s) emissions will be maintained under barrier fluid pressure vessels and periodically purge to the flare system by nitrogen. Initial and periodic performance testing/monitoring for the equipment will be conducted as applicable and initial and quarterly reports will be submitted as required. Delays of repair will be conducted as allowed by this subpart.

Per § 60.590a(c), addition or replacement of equipment (defined in § 60.591a) for the purpose of process improvement which is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

The additions and replacements for the Sat-Gas Unit resulted in a capital expenditure and resulted in a modification of the Sat-Gas Unit and the #2 SWS Unit. Therefore, they are subject to this subpart. Initial and periodic performance testing/monitoring for the equipment was conducted as applicable and initial and quarterly reports will be submitted as required.

Subpart III, VOC Emissions from SOCMI Air Oxidation Unit Processes. This subpart affects facilities with air oxidation reactors that produce, as a product, co-product, by-product, or intermediate, any of the chemicals listed in § 60.617. The Asphalt Blowstill is the only air oxidation process at the facility and it does not produce a listed chemical.
Subpart KKK, Equipment Leaks of VOC from Onshore Natural Gas Processing Plants. This subpart sets standards for natural gas processing plants which are defined as any site engaged in the extraction of natural gas liquids from field gas, fractionation of natural gas liquids, or both. This facility does not extract natural gas liquids from field gas or fractionate natural gas liquids.

Subpart LLL, Onshore Natural Gas Processing: SO_2 Emissions. This subpart affects each sweetening unit and each sweetening unit followed by a SRU that process natural gas which commenced construction or modification after January 20, 1984. Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface. This facility only processes gases that are generated at the facility from the processing of crude oil.

Subpart NNN, VOC Emissions from SOCMI Distillation Operations. This subpart affects facilities that are a part of a process unit that produce, as a product, co-product, by-product, or intermediate, any of the chemicals listed in § 60.667. This facility produces listed chemicals and uses distillation to separate the desired product. However, none of the distillation and recovery process streams are vented to the atmosphere.

Subpart OOO, Nonmetallic Mineral Processing Plants. This subpart affects each crusher, grinding mill, screening operation, bucket elevator, belt conveyor, bagging operation, storage bin, enclosed truck or railcar loading station at nonmetallic mineral processing plants. This facility does not crush or grind any nonmetallic minerals.

Subpart QQQ, VOC Emission from Petroleum Refinery Wastewater Systems. This subpart applies to individual drain systems, oil-water separators, and aggregate facilities located in a petroleum refinery and which commenced construction, modification, or reconstruction after May 4, 1987. Drains are required to be equipped with water seal controls. Junction boxes are required to be equipped with a cover and may have an open vent pipe. Sewer lines shall not be open to the atmosphere and shall be covered or enclosed in a manner so as to have no visual gaps or cracks in joints, seals, or other emission interfaces. Oil-water separators shall be equipped with a fixed roof or a floating roof, which meets the required specifications.

Group 1 wastewater streams that are managed under this subpart that are also subject to the provisions of NESHAP, Subpart CC are only required to comply with Subpart CC which requires compliance with NESHAP, Subpart FF. Subpart FF allows oil-water separators to comply with the requirements for alternative standards for oil-water separators of Subpart QQQ. This facility is subject to the requirements of NESHAP, Subpart CC.

The Oil-Water Separators (V-8801 & V-8802) comply with the Alternative Standards for Oil-Water Separators of this subpart. Storage vessel T-83001 which handles a Group 2 wastewater stream is also subject to the requirements of this subpart (§ 60.692-3). T-1152 which is subject to the standards in § 60.112b and associated requirements is not subject to the requirements of § 60.692-3. All applicable requirements have been incorporated into this permit.

Subpart RRR, VOC Emissions from SOCMI Reactor Processes. This subpart affects facilities that are a part of a process unit that produce, as a product, co-product, by-product, or intermediate, any of the chemicals listed in § 60.707. This facility produces listed chemicals and has a reactor to produce the desired products. However, all streams from the reactors are recovered. There are no vent streams to control.

Subpart IIII, Stationary Compression Ignition (CI) Internal Combustion Engines (ICE). This subpart affects owners/operators of CI ICE that commence construction, reconstruction, or modification after July 11, 2005 that were manufactured after April 1, 2006 that are not fire pump engines and manufacturers of 2007 model year CI-ICE with a displacement of less than 30 L/Cylinder that are not fire pump engines. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

"Stationary internal combustion engine" means any ICE, except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary ICE is **not** a nonroad engine as defined at 40 CFR § 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle or a vehicle used solely for competition. "Nonroad engine," as defined in 40 CFR § 1068.30, means:

1. Nonroad engine is an ICE that meets any of the following criteria:

   i. It is (or will be) used in or on a piece of equipment that is self-propelled or serves a dual purpose by both propelling itself and performing another function (such as garden tractors, off-highway mobile cranes and bulldozers).
   ii. It is (or will be) used in or on a piece of equipment that is intended to be propelled while performing its function (such as lawnmowers and string trimmers).
   iii. By itself or in or on a piece of equipment, it is portable or transportable, meaning designed to be and capable of being carried or moved from one location to another. Indicia of transportability include, but are not limited to, wheels, skids, carrying handles, dolly, trailer, or platform.

An engine that remains or will remain at a location for more than 12 consecutive months is not a nonroad engine. Any engine (or engines) that replace an engine at a location and that is intended to perform the same or similar function as the engine replaced will be included in calculating the consecutive time period. Therefore, even if the engines are portable, for the purposes of NSPS, Subpart IIII, they are considered stationary sources while at the refinery and being operated as a replacement for a permanent function such as Instrument/Plant Air Compressor.

The following engines were constructed after the applicability date of this subpart and are subject to this subpart.

EUG	EU	Make/Model	KW (HP)	Const. Date
20	EG1880-02	Cummins QSTB-G5	100 (134)	2012
20	EG-ADMIN	Cummins QSX15-G9	400 (536)	2018
40	P850A	Deutz F4914	61.5 (82.5)	2006
40	P850D	John Deere 4045TF 280B	63.0 (84.0)	2010

Per §§ 60.4205(a) and 4204(a), pre-2007 model year emergency and non-emergency engines, with a displacement of < 10 L/Cylinder, that are not fire pump engines, must comply with the emission standards in Table 1 of Subpart IIII. EU P850A is subject to this emission limit.

Table 1 of Subpart IIII
Non-Road CI-RICE Emission Limits
g/kW-hr (g/hp-hr)

Maximum Engine Power	NO_X
56 ≥ kW < 75 (75 ≥ HP < 100)	9.2 (6.9)

Per §§ 60.4205(b) and 4204(b), 2007 model year and later emergency and non-emergency engines with a displacement of < 30 L/Cylinder must comply with the emission standards for new CI engines in §§ 60.4202 and 4201. Per §§ 60.4202(a) and 4201(a), 2007 model year and later emergency and non-emergency engines, with a maximum engine power less than 3,000-hp and > 50-hp, with a displacement of < 10 L/Cylinder must be certified to the non-road diesel engine standards of § 89.112 and the smoke standards of § 89.113. EU EG1880-02, P850D, and EG-ADMIN are subject to these emission limits.

40 CFR Part 89, Non-Road CI-RICE Emission Standards, g/kW-hr (g/hp-hr)

Tier	kW	Model Years	NO_X+HC	CO	PM
III	37 ≥ kW < 75	2008-2013	4.7 (3.5)	5.0 (3.7)	0.40 (0.30)
III	75 ≥ kW < 130	2007-2013	4.0 (3.0)	5.0 (3.7)	0.30 (0.22)

To demonstrate compliance with the emission standards, owner/operators may purchase an engine certified according to 40 CFR Part 89, keep records of performance testing conducted on a similar engine, keep records of engine manufacturer data indicating compliance with the standards, keep records of control device vendor data indicating compliance with the standards, or conduct initial performance tests according to § 60.4212. The facility purchased certified engines.

Owners/operators of stationary CI ICE must operate and maintain stationary CI ICE according to the manufacturer's written instructions or procedures developed by the owner/operator that are approved by the engine manufacturer, over the entire life of the engine. In addition, owners/operators may only change those settings that are permitted by the manufacturer. After October 1, 2010, owners/operators of stationary CI ICE subject to Subpart IIII must use diesel fuel that meets the requirements of 40 CFR § 80.510(b) (<15 ppmw S).

Emergency stationary ICE may be operated for any combination of the purposes specified below for a maximum of 100 hours per calendar year:

1. Maintenance checks and readiness testing;
2. Emergency demand response under NERC Energy Emergency Alert Level 2; and
3. During deviations of voltage or frequency of 5 % or greater below standard voltage or frequency.
   i. Emergency stationary ICE may be operated up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response.

There is no time limit on the use of emergency stationary ICE in emergency situations. All applicable requirements have been incorporated into the permit.

Subpart JJJJ, Stationary Spark Ignition Internal Combustion Engines (SI-ICE). This subpart promulgates emission standards for all new SI engines ordered after June 12, 2006, and all SI engines modified or reconstructed after June 12, 2006, regardless of size. The specific emission standards (either in g/hp-hr or as a concentration limit) vary based on engine class, engine power rating, lean-burn or rich-burn, fuel type, duty (emergency or non-emergency), and numerous manufacture dates. Engine manufacturers are required to certify certain engines to meet the emission standards and may voluntarily certify other engines. An initial notification is required only for owners and operators of engines greater than 500 HP that are non-certified. Emergency engines are required to be equipped with a non-resettable hour meter and are limited to 100 hours per year of operation excluding use in an emergency (the length of operation and the reason the engine was in operation must be recorded).

This subpart affects owners and operators of emergency stationary SI ICE that commence construction after June 12, 2006, where the stationary SI ICE is manufactured on or after January 1, 2009. The following engine was constructed after the applicability date of this subpart and is subject to this subpart.

EUG	EU	Make/Model	KW (HP)	Const. Date
20	EG1880-01	Cummins WSG-1068	85.5 (115)	2009

Per § 60.4233(e), owners and operators of stationary SI ICE with a maximum engine power ≥ 100-hp must comply with the emission standards in Table 1 of Subpart JJJJ for their stationary SI ICE. EU EG1880-02 is subject to these emission limits.

Emission Standards from Table 1, Subpart JJJJ, g/hp-hr

Engine Type & Fuel	Max Power (hp)	Mfg. Date	NO_X	CO
Emergency	25 < hp < 130	1/1/2009	10	387

The owner/operator of stationary SI-ICE > 25-hp and ≤ 500-hp must demonstrate compliance by purchasing a certified engine or conducting an initial performance test and keeping a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. The owner/operator purchased a certified engine.

Emergency stationary ICE may be operated for any combination of the purposes specified below for a maximum of 100 hours per calendar year:

1. Maintenance checks and readiness testing;
2. Emergency demand response under NERC Energy Emergency Alert Level 2; and
3. During deviations of voltage or frequency of 5 % or greater below standard voltage or frequency.
   i. Emergency stationary ICE may be operated up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response.

There is no time limit on the use of emergency stationary ICE in emergency situations. All applicable requirements have been incorporated into the permit.

NESHAP, 40 CFR Part 61 [Subpart FF is Applicable]
Subpart J, Equipment Leaks (Fugitive Emission Sources) of Benzene. This subpart affects process streams that contain more than 10% benzene by weight. The maximum benzene concentration in

any product stream at this site is 5% in super unleaded gasoline, and only trace amounts are expected in the refinery fuel gas.

Subpart FF, Benzene Waste Operations. This subpart affects benzene-contaminated wastewater at petroleum refineries. Facilities with 10 metric tons of benzene are required to manage and treat the waste streams. This facility has elected to manage and treat the facility wastes such that the uncontrolled benzene quantity in the wastes is equal to or less than 6.0 metric tons per year.

NESHAP, Part 63, Subpart CC, requires all Group 1 wastewater streams to comply with §§ 61.340 through 61.355 of 40 CFR Part 61, Subpart FF, for each process wastewater stream that meets the definition in § 63.641. All applicable requirements have been incorporated into this permit.

NESHAP, 40 CFR Part 63 [Subparts CC, WW, UUU, ZZZZ, DDDDD, GGGGG, and LLLLL are Applicable]

Subpart G, OHAP from the SOCMI for Process Vents, Storage Vessels, Transfer Operations, and Wastewater. Subpart CC requires all Group 1 storage vessels to comply with §§ 63.119 through 63.121 of Subpart G. The Group 1 storage vessels are listed in the NESHAP, Subpart CC section. Storage Vessels subject to the standards of NSPS, Subpart Kb are not subject to these requirements due to the overlap provisions of NESHAP, Subpart CC.

Subpart Q, Industrial Cooling Towers. This subpart applies to all new and existing industrial process cooling towers that are operated with chromium-based water treatment chemicals on or after September 8, 1994, and are either major sources or are integral parts of facilities that are major sources as defined in § 63.401. This facility does not have or use industrial process cooling towers that are operated with chromium-based water treatment chemicals.

Subpart R, Gasoline Distribution Facilities. Bulk gasoline terminals or pipeline breakout stations with a Standard Industrial Classification code 2911 located within a contiguous area and under common control with a refinery complying with Subpart CC, §§ 63.646, 63.648, 63.649, and 63.650 are not subject to this subpart, except as specified in Subpart CC, § 63.650. Subpart CC, § 63.650(a) requires all facilities to comply with Subpart R, §§ 63.421, 63.422 (a) through (c), 63.425 (a) through (c), 63.425 (e) through (h), 63.427 (a) and (b), and 63.428 (b), (c), (g)(1), and (h)(1) through (h)(3). Subpart CC § 63.650(b) states that all terms not defined in § 63.641 shall have the meaning given them in Subpart A or in 40 CFR part 63, Subpart R and that the definition of "affected source" in § 63.641 applies under this section. § 63.650(c) requires all gasoline loading racks regulated under Subpart CC to comply with the compliance dates specified in § 63.640(h). All applicable requirements, per Subpart CC, are incorporated into the permit.

Subpart CC, Petroleum Refineries. This subpart applies to petroleum refining process units and to related emissions points that make up an affected source that are located at a plant site that is a major source of HAP and that emits or has equipment containing or contacting one or more of the listed HAP. The affected source comprises all emissions points, in combination, listed below that are located at a single refinery plant site.

1. All miscellaneous process vents from petroleum refining process units;
2. All storage vessels associated with petroleum refining process units;

3. All wastewater streams and treatment operations associated with petroleum refining process units;
4. All equipment leaks from petroleum refining process units;
5. All gasoline loading racks classified under Standard Industrial Classification code 2911;
6. All marine vessel loading operations located at a petroleum refinery meeting the applicability criteria of subpart Y, § 63.560;
7. All storage vessels and equipment leaks associated with a bulk gasoline terminal or pipeline breakout station classified under Standard Industrial Classification code 2911 located within a contiguous area and under common control with a refinery; and
8. All heat exchange systems, as defined in this subpart.

Petroleum refining process units are defined as a process unit engaged in petroleum refining as defined in the SIC code for petroleum refining (SIC 2911) and used primarily for the following:

1. Producing transportation fuels (such as gasoline, diesel fuels, and jet fuels), heating fuels (such as kerosene, fuel gas distillate, and fuel oils), or lubricants;
2. Separating petroleum; or
3. Separating, cracking, reacting, or reforming intermediate petroleum streams.

Examples of such units include, but are not limited to, petroleum-based solvent units, alkylation units, catalytic hydrotreating, catalytic hydrorefining, catalytic hydrocracking, catalytic reforming, catalytic cracking, crude distillation, lube oil processing, hydrogen production, isomerization, polymerization, thermal processes, and blending, sweetening, and treating processes. Petroleum refining process units also include sulfur plants. Catalytic cracking unit catalyst regeneration vents, catalytic reformer regeneration vents, sulfur recovery plant vents and fuel gas emission points were specifically exempted from this subpart. The affected emission points are listed with a summary of applicable requirements.

<u>Miscellaneous Process Vents From Petroleum Refining Process Units</u>
Miscellaneous process vent means a gas stream containing greater than 20 ppmv organic HAP that is continuously or periodically discharged during normal operation of a petroleum refining process unit meeting the criteria specified in § 63.640(a). Miscellaneous process vents include gas streams that are discharged directly to the atmosphere, gas streams that are routed to a control device prior to discharge to the atmosphere, or gas streams that are diverted through a product recovery device prior to control or discharge to the atmosphere. Miscellaneous process vents include vent streams from: caustic wash accumulators, distillation tower condensers/accumulators, flash/knockout drums, reactor vessels, scrubber overheads, stripper overheads, vacuum (steam) ejectors, wash tower overheads, water wash accumulators, blowdown condensers/accumulators, and delayed coker vents. Miscellaneous process vents do not include:

1. Gaseous streams routed to a fuel gas system;
2. Relief valve discharges;
3. Leaks from equipment regulated under § 63.648;
4. Episodic or nonroutine releases such as those associated with startup, shutdown, malfunction, maintenance, depressuring, and catalyst transfer operations;
5. In situ sampling systems (onstream analyzers);

6. Catalytic cracking unit catalyst regeneration vents;
7. Catalytic reformer regeneration vents;
8. Sulfur plant vents;
9. Vents from control devices such as scrubbers, boilers, incinerators, and electrostatic precipitators applied to catalytic cracking unit catalyst regeneration vents, catalytic reformer regeneration vents, and sulfur plant vents;
10. Vents from any stripping operations applied to comply with the wastewater provisions of this subpart, Subpart G of this part, or 40 CFR part 61, subpart FF;
11. Coking unit vents associated with coke drum depressuring at or below a coke drum outlet pressure of 15 pounds per square inch gauge, deheading, draining, or decoking (coke cutting) or pressure testing after decoking;
12. Vents from storage vessels;
13. Emissions from wastewater collection and conveyance systems including, but not limited to, wastewater drains, sewer vents, and sump drains; and
14. Hydrogen production plant vents through which carbon dioxide is removed from process streams or through which steam condensate produced or treated within the hydrogen plant is degassed or deaerated.

The Valero Ardmore Refinery currently has 87 process vents which might be defined as Group 1 miscellaneous process vents. Of these vents, 13 are routed to the fuel gas recovery, treatment, and distribution system(s) and are not defined as miscellaneous process vents. The remaining 74 process vents serve various processing functions and are either routed back to the process heaters, incinerators, or to one of the two flares. All applicable requirements have been incorporated into the permit for these vents.

Storage Vessels Associated with Petroleum Refining Process Units, Bulk Gasoline Terminals, or Pipeline Breakout Stations

Group 1 storage vessels at an existing source are storage vessels with a design capacity greater than or equal to 46,758.5 gallons (1,113.3 barrels) that store a liquid with a maximum true vapor pressure (MTVP) greater than or equal to 1.5 psia and an annual average true vapor pressure greater than or equal to 1.2 psia and has an annual average HAP concentration greater than 4 % by weight. Group 2 storage vessels means a storage vessel that does not meet the definition of a Group1 storage vessel.

Group 1 Storage Vessels Subject to NESHAP, Subpart CC

				MTVP	
EU	**Roof Type**	**Contents**	**Barrels**	**Psia**	**% HAP**
T-1018R	External Floating	NHT Charge	62,580	≥ 1.5	>4.0
T-1019	External Floating	Alkylate	66,868	≥ 1.5	>4.0
T-1082	External Floating	Crude Oil	124,714	≥ 1.5	>4.0
T-1083	External Floating	Crude Oil	124,714	≥ 1.5	>4.0
T-1084	External Floating	Crude Oil	124,714	≥ 1.5	>4.0
T-1115	External Floating	Gasoline	27,205	≥ 1.5	>4.0
T-1116	External Floating	Gasoline	27,315	≥ 1.5	>4.0
T-1123	External Floating	Gasoline	60,766	≥ 1.5	>4.0
T-1124	External Floating	Gasoline	111,721	≥ 1.5	>4.0

Group 1 Storage Vessels Subject to NESHAP, Subpart CC

EU	Roof Type	Contents	Barrels	MTVP Psia	% HAP
T-1125	External Floating	Gasoline	124,398	≥ 1.5	>4.0
T-1126	External Floating	Gasoline	124,412	≥ 1.5	>4.0
T-1130	External Floating	FCCU Gasoline	79,414	≥ 1.5	>4.0
T-1131	External Floating	Gasoline	125,100	≥ 1.5	>4.0
T-1132	External Floating	Reformate	80,138	≥ 1.5	>4.0

Group 2 Storage Vessels Subject to NESHAP, Subpart CC

EU	Roof Type	Contents	Barrels	MTVP Psia	% HAP
T-1113	Cone	Gas Oil / Asphalt	131,005	<1.5	≤ 4.0
T-1127	Cone	Diesel/Kerosene	80,579	<1.5	≤ 4.0
T-1129	Cone	Diesel/Kerosene	2,113	<1.5	≤ 4.0
TK-13006	Cone	Fuel Additives	485	<1.5	≤ 4.0

Group 2 storage vessels are subject to the recordkeeping requirements of this subpart. The permit incorporates all applicable requirements.

Group 1 and Group 2 storage vessels that are part of an existing source and subject to the provisions of NSPS, Subpart Kb are only required to comply with the provisions of NSPS, Subpart Kb except as provided in § 63.640(n)(8)(i) through (vi). These storage vessels are listed in the NSPS, Subpart Kb section. Group 1 storage vessels that are part of an existing source and subject to the provisions of NSPS, Subparts K or Ka are only required to comply with this subpart. Group 2 storage vessels that are part of an existing source and that are subject to the control requirements of NSPS, Subparts K or Ka are only required to comply with NSPS, Subparts K or Ka. Group 2 storage vessels that are part of an existing source and that are not subject to the control requirements of NSPS, Subparts K or Ka are only required to comply with this subpart.

Group 1 Storage Vessels not subject to NSPS, Subpart Kb are required to comply with the requirements of §§ 63.119 through 63.121 except as provided in § 63.646(b) through § 63.646(l). The owner or operator of these storage vessels are required to reduce HAP emissions to the atmosphere either by operating and maintaining a fixed roof and internal floating roof, an external floating roof, an external floating roof converted to an internal floating roof, or a closed vent system and control device, or routing the emissions to a process or a fuel gas system. The facility is also required to meet certain work practices and conduct inspections and maintain the tank seals similar to the requirements of NSPS, Subpart Kb. All applicable requirements have been incorporated into the permit.

<u>Wastewater Streams and Treatment Operations Associated w/Petroleum Refining Process Units</u>
The wastewater streams and treatment operations associated with petroleum refining process units in organic HAP service are subject to this subpart and are required to comply with the requirements of this subpart. This subpart requires equipment that is used to manage a Group 1 wastewater stream to comply with the requirements of this subpart and 40 CFR §§ 61.340 through 61.355, NESHAP, Subpart FF. For Group 1 wastewater streams managed in a piece of equipment that is

also subject to the provisions of NSPS, Subpart QQQ the equipment is only required to comply with the requirements of this subpart. All applicable requirements have been incorporated into the permit.

Equipment Leaks from Petroleum Refining Process Units, Bulk Gasoline Terminals, or Pipeline Breakout Stations
All equipment in organic HAP service is required to comply with the provisions of 40 CFR Part 60, Subpart VV and 63.648(b), except as provided in § 63.648(a)(1), (a)(2), and (c) through (i). All equipment subject to NSPS, Subpart GGG and this subpart is only required to comply with this subpart. Equipment leaks that are also subject to the provisions of NSPS, Subpart GGGa, are only required to comply with the provisions specified in NSPS Subpart GGGa. All applicable requirements have been incorporated into the permit.

Gasoline Loading Racks or Pipeline Breakout Stations
Gasoline loading racks are required to comply with Subpart R, §§ 63.421, 63.422 (a) through (c), 63.425 (a) through (c), 63.425 (e) through (h), 63.427 (a) and (b), and 63.428 (b), (c), (g)(1), and (h)(1) through (h)(3). As stated in the overlap provisions, a Group 1 gasoline loading rack that is part of a source subject to subpart CC which is also subject to the provisions of NSPS, Subpart XX is required to only comply with this subpart. The Light Products Loading Rack and alkylate/gasoline railcar loading rack are subject to this section. All applicable requirements have been incorporated into the permit. This facility does not have a pipeline breakout station.

Marine Vessel Loading Operations
There are no marine vessel loading operations at this facility.

Heat Exchange Systems
The owner or operator must perform monitoring to identify leaks of total strippable VOC from each heat exchange system subject to the requirements of this subpart. A heat exchange system is exempt if all heat exchangers within the heat exchange system either:

1. Operate with the minimum pressure on the cooling water side at least 35 kilopascals greater than the maximum pressure on the process side; or
2. Employ an intervening cooling fluid containing less than 5% by weight of total organic HAP between the process and the cooling water.

If a leak is detected, the owner or operator must repair the leak to reduce the measured concentration to below the applicable action level as soon as practicable, but no later than 45 days after identifying the leak, except as specified in § 63.654(e) and (f).

On January 30, 2019, additional requirements became applicable to flares used a control device for any emission point subject to Subpart CC. Under § 63.670, subject flares are required to meet specifications for the flare combustion zone heating value (NHV_{cz}), 270 Btu/scf, determined on a 15-minute block period basis when regulated material is routed to the flare for at least 15 minutes. The permit includes the requirement to abide by all applicable requirements of this subpart.

EUG 42A (CFHT Cooling Tower), 42B (Ceramic Cooling Tower), 42C (Alkylation Cooling Tower), and 42D (STG Cooling Tower) are induced draft cooling towers with heat exchangers where the pressure exceeds the cooling water pressure and which have a HAP Concentration which is greater than 5 % and are subject to the monitoring requirements of this subpart. The individual heat exchangers which are required to be monitored are listed within each EUG. All applicable requirements have been incorporated into the permit.

Subpart WW, Storage Vessels (Tanks) - Control Level 2. This subpart establishes control requirements for storage vessels for which another subpart references the use of this subpart. The standards are placed in this subpart for reference purposes. In the case of the storage tanks identified below, MACT CC establishes applicable requirements for storage vessels located at a plant site that is a major source of HAPs and Subpart WW specifies the control requirements.

Storage Tanks Subject to NESHAP, Subparts CC and WW

EUG	EU	Roof Type	Contents	Regulatory Applicability	Compliance Date for MACT WW Requirements
1A	T-1019	External Floating	Alkylate/Gasoline	MACT CC – Group 1	6/6/2017
1A	T-1082	External Floating	Crude Oil	MACT CC – Group 1	2/1/2026
1A	T-1083	External Floating	Crude Oil	MACT CC – Group 1	2/1/2026
1A	T-1084	External Floating	Crude Oil	MACT CC – Group 1	2/1/2026
1A	T-1115	External Floating	Gasoline with Ethanol	MACT CC – Group 1	2/1/2026
1A	T-1116	External Floating	Gasoline with Ethanol	MACT CC – Group 1	2/1/2026
1A	T-1123	External Floating	Gasoline/Diesel	MACT CC – Group 1	2/28/2017
1A	T-1124	External Floating	Gasoline	MACT CC – Group 1	2/1/2026
1A	T-1125	External Floating	Gasoline	MACT CC – Group 1	2/1/2026
1A	T-1126	External Floating	Gasoline	MACT CC – Group 1	5/27/2020
1A	T-1130	External Floating	Gasoline	MACT CC – Group 1	9/4/2019
1A	T-1131	External Floating	Gasoline/FCCU Gasoline ISOM/Hydrocracker Naphtha	MACT CC – Group 1	2/1/2026
1A	T-1132	External Floating	Reformate	MACT CC – Group 1	2/1/2026
1B	T-1018R	External Floating	Alkylate/Gasoline	MACT CC – Group 1	12/20/2018
3	T-1152	External Floating	Sour Water Stripper Feed	MACT CC – Group 1	2/1/2026
3	T-100160	Internal Floating	Ethanol	MACT CC – Group 1	2/1/2026
6	V-8801	External Floating	Oil/Water	MACT CC/NESHAP FF	2/1/2026
6	V-8802	External Floating	Oil/Water	MACT CC/NESHAP FF	2/1/2026

All emissions controls are required to be installed during the next tank degassing, but no later than February 1, 2026. Some of the tanks have already passed their compliance dates and Valero has completed the necessary equipment upgrades and/or retrofits necessary to comply with MACT WW. The following table summarizes changes made so far.

Retrofits and Upgrades Made to Comply with MACT WW

EU	Leg Socks (Installed/ Secured)	Hatches (Gasketed)	Hatches (Fastened)	Slotted Guidepole (Y/N)	Slotted Guidepole Sealed (Y/N)	Compliance Date for MACT WW Requirements
T-1019	Yes	Yes	Yes	No	--	6/6/2017
T-1116	--	Yes	Yes	No	N/A	2/1/2026
T-1123	Yes	Yes	Yes	--	--	2/28/2017
T-1126	Yes	Yes	Yes	No	--	5/27/2020
T-1130	Yes	Yes	Yes	Yes	Yes	9/4/2019
T-1018R	Yes	Yes	Yes	No	--	12/20/2018

Subpart UUU, Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and SRU. This subpart, affects the following EUs:

1. The process vent or group of process vents on fluidized catalytic cracking units that are associated with regeneration of the catalyst used in the unit (*i.e.*, the catalyst regeneration flue gas vent);
2. The process vent or group of process vents on catalytic reforming units (including but not limited to semi-regenerative, cyclic, or continuous processes) that are associated with regeneration of the catalyst used in the unit. This affected source includes vents that are used during the unit depressurization, purging, coke burn, and catalyst rejuvenation;
3. The process vent or group of process vents on Claus or other types of sulfur recovery plant units or the tail gas treatment units serving sulfur recovery plants, that are associated with sulfur recovery; and
4. Each bypass line serving a new, existing, or reconstructed catalytic cracking unit, catalytic reforming unit, or sulfur recovery unit. This means each vent system that contains a bypass line (e.g., ductwork) that could divert an affected vent stream away from a control device used to comply with the requirements of this subpart.

An affected source is a new affected source if the facility commenced construction of the affected source after September 11, 1998. An affected source is an existing affected source if it is not new or reconstructed. All existing affected sources were required to comply with this subpart by April 11, 2005, except as provided by § 63.1563(c). All new sources are required to comply with this subpart as follows:

1. If startup of the new affected source was prior to April 11, 2002, then it must comply with the emission limitations and work practice standards for new and reconstructed sources in this subpart no later than April 11, 2002.
2. If startup of the new affected source was after April 11, 2002, then it must comply with the emission limitations and work practice standards for new and reconstructed sources in this subpart upon startup of the affected source.

FCCU Catalyst Regeneration Flue Gas Vents

Inorganic HAP Standard

Catalytic cracking units subject to the NSPS, Subpart J, PM emissions limit (≤ 1 lb/1,000 of coke burn off) must comply with the NSPS Subpart J, PM emission limit. The FCCU regenerators are subject to the NSPS, Subpart J emission limit and comply with that limit.

Since the facility uses a wet scrubber to control emissions, the facility applied for an AMP to include monitoring of the liquid-to-gas ratio rather than a continuous opacity monitor (COM) to show compliance with this standard. The facility is required to monitor the coke burn off rate daily and the hours of operation of the FCCU Regenerators. Since the CO boilers do not combust solid or liquid fossil fuels, fuel combustion monitoring is not required for the CO boilers. As an alternative to a COMS and pursuant to a submitted AMP and Part 5a Schedule of Compliance, the facility monitors and records the L/G ratio to assess compliance with the PM limitation and the opacity standard.

Organic HAP Standard

Catalytic cracking units subject to the NSPS, Subpart J, CO emissions limit (≤ 500 ppmdv @ 0% O_2) must comply with the NSPS Subpart J, CO emission limit. The FCCU regenerators are subject to the NSPS, Subpart J emission limit and comply with that limit. The FCCU uses a CEM to show compliance with this standard on an hourly basis.

Catalytic Reforming Unit Process Vents

The Platformer CCR is a catalytic reforming unit and will be subject to this subpart.

Organic HAP Standard

Catalytic reforming units must comply with one of the organic HAP emission limits of § 63.1567(a)(1)(i) (vent to a flare that meets the control device requirements of § 63.11) or (ii) (reduce uncontrolled TOC emissions by 98 % or to less than 20 ppmvd @ 3% O_2) during initial catalyst depressuring and catalyst purging operations that occur prior to the coke burn-off cycle. These emission limits do not apply to the coke burn-off, catalyst rejuvenation, reduction or activation vents, or to the control systems used for these vents. They also do not apply to emissions from process vents during depressuring and purging operations when the reactor vent pressure is 5 pounds per square inch gauge (psig) or less.

The facility complies with both options depending upon the operating periods within the CCR operation cycle. The facility is required to continuously monitor the flare's pilot light for the presence of a flame and the daily average combustion zone temperature of the heaters used to control emissions. When vent streams are introduced into the flame zone of the process heaters, no monitoring is required. The CCR purge and depressurization gases are vented to the flame zones of H-403 and H-404/H-405. The pilot light of the west flare is monitored continuously.

Inorganic HAP Standard

Continuous catalytic reforming units must comply with the inorganic HAP emission limits of § 63.1566(a)(1)(ii) (reduce uncontrolled emissions of HCl by 97% by weight or to a concentration of 10 ppmvd @ 3% O_2) during coke-burn off and catalyst rejuvenation. The facility installed a wet scrubber and vents the emissions from the coke burn off and rejuvenation to the wet scrubber. The facility is required to monitor the daily average pH of the scrubbing liquid and liquid to gas ratio and maintain them at or above levels established during the initial performance tests (≥ 8.0 and 1.85, respectively).

<u>Sulfur Recovery Units</u>

Sulfur recovery units subject to the NSPS, Subpart J, SO_2 emission limit (≤ 250 ppmvd @ 0% O_2) must comply with the NSPS Subpart J, SO_2 emission limit. The new and existing SRUs are subject to NSPS, Subpart J and will meet all applicable requirements of this subpart and NSPS, Subpart J. The SRU use a CEM to show compliance with this standard on a 12-hour rolling average basis.

<u>Bypass Lines</u>

Bypass lines must meet the work practice standards in Table 36 of this subpart. There are no bypass lines for the FCCU. The SRUs have bypass lines that are vented to the east flare system. The CCR bypass valve to the atmosphere has a car seal which can be bypassed in an emergency situation. The facility uses flow monitoring devices to determine if flow is present in the lines hourly. EUG 43 (Bypass Pressure Control Valves (BPCV) & Bypass Block Valves (BBV)) lists the bypass lines which are subject to this subpart.

Operation, maintenance, and monitoring plans were required to be prepared and submitted for the FCCU, CCR, SRUs, and Bypass Lines. The facility submitted the plans with their initial compliance demonstration and their startup, shutdown, and malfunction plan. All applicable requirements have been incorporated into the permit.

<u>Subpart EEEE</u>, Organic Liquids Distribution (Non-Gasoline). This subpart affects organic liquid distribution (OLD) operations at major sources of HAP with an organic liquid throughput greater than 7.29 million gallons per year (173,571 barrels/yr). This subpart affects the following EU at existing facilities:

1. Storage Vessels with a capacity ≥ 20,000 gallons but < 40,000 gallons that store an organic liquid that contains > 5% HAP and that has an annual average vapor pressure ≥ 1.9 but < 11.1 psia;
2. Storage Vessels with a capacity ≥ 40,000 gallons that store an organic liquid that contains > 5% HAP and that has an annual average vapor pressure ≥ 0.75 psia.
3. Transfer racks that loads at any position ≥ 11.8 million liters (3.12 million gallons) per year of organic liquids into a combination of tank trucks and railcars.

Sources controlled under another NESHAP are exempt from this subpart. There are no OLD operations subject to this subpart.

<u>Subpart ZZZZ</u>, Reciprocating Internal Combustion Engines (RICE). This subpart affects any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions. Owners and operators of the following new or reconstructed RICE must meet the requirements of Subpart ZZZZ by complying with either 40 CFR Part 60 Subpart IIII (for CI engines) or 40 CFR Part 60 Subpart JJJJ (for SI engines):

1. Stationary RICE located at an area source;
2. The following Stationary RICE located at a major source of HAP emissions:
   i. 2SLB and 4SRB stationary RICE with a site rating of ≤ 500 brake HP;
   ii. 4SLB stationary RICE with a site rating of < 250 brake HP;

iii. Stationary RICE with a site rating of ≤ 500 brake HP which combust landfill or digester gas equivalent to 10% or more of the gross heat input on an annual basis;
iv. Emergency or limited use stationary RICE with a site rating of ≤ 500 brake HP; and
v. CI stationary RICE with a site rating of ≤ 500 brake HP.

No further requirements apply for these engines. RICE > 500-hp located at a major source are new or reconstructed if construction or reconstruction commenced after December 19, 2002. RICE ≤ 500-hp located at a major source are new or reconstructed if construction or reconstruction commenced after June 12, 2006. The engines listed below fall into the new or reconstructed category of engines subject to NSPS.

EUG	EU	Make/Model	KW (HP)	Const. Date	NSPS
20	EG1880-01	Cummins WSG-1068	85.5 (115)	2009	JJJJ
20	EG1880-02	Cummins QSTB-G5	100 (132)	2012	IIII
20	EG-ADMIN	Cummins QSX15-G9	400 (536)	2018	IIII
40	P850A	Deutz F4914	61.5 (82.5)	2006	IIII
40	P850D	John Deere 4045TF 280B	63 (84)	2010	IIII

The following engines at major sources do not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of § 63.6645(f):

1. New or reconstructed emergency stationary RICE > 500-hp located at a major source of HAP emissions that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) [emergency demand response] and (iii) [deviation of voltage or frequency of ≥ 5%].
2. New or reconstructed limited use stationary RICE with a site rating of > 500-hp.

The engines listed in the following table are only required to meet the initial notice requirements.

EUG	EU	Make/Model	KW (HP)	Const. Date
20	P1807A	Caterpillar 3412 HRM	(800)	2004
20	P1807B	Caterpillar 3412 HRM	(800)	2004
20	P1807C	Caterpillar 3412 HRM	(800)	2004

The following stationary RICE at major sources do not have to meet the requirements of this subpart and of Subpart A of this part, including initial notification requirements:

1. Existing spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating > 500-hp;
2. Existing spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating > 500-hp;
3. Existing emergency stationary RICE with a site rating > 500-hp that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in § 63.6640(f)(2)(ii) and (iii).
4. Existing limited use stationary RICE with a site rating > 500-hp; and
5. Existing stationary RICE with a site rating of > 500-hp that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

The engines listed in the following table are in this category and are not subject to this subpart.

EUG	EU	Make/Model	KW (HP)	Const. Date
20	EEQ-8801	Detroit DMT 825D-2	750 (1,006)	1994
22	C-80018	Cummins N14-C475	372.9 (500)	1993

The remaining engines which are subject to this subpart are listed in the following table.

EUG	EU	Make/Model	KW (HP)	Const. Date
20	P1806	Cummins NT-855-F2	283.4 (380)	1976
40	P850B	Deutz F4912	54 (72.5)	1995
40	P850C	John Deere 4045DF 270B	60 (80)	2004
40	P850E	John Deere 4045TF 275B	86 (115)	2003
40	FWPE-1	Caterpillar 3406C	345 (460)	2002

P1806 is an existing emergency CI engine > 100-hp and is subject to the following requirements.

RICE Category	Emission Limit/Operating Limits
Existing, Emergency, Black Start, CI RICE	Change oil and filter every 500 hours of operation or annually, whichever comes first;
	Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and
	Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.

P850B, P850C, P850E, and FWPE-1 are not emergency engines and are subject to the following requirements.

RICE Category	Emission Limit/Operating Limits
Existing, Non-Emergency, Non-Black Start CI RICE, HP < 100-hp	Change oil and filter every 1,000 hours of operation or annually, whichever comes first;
	Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and
	Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.
Existing, Non-Emergency, Non-Black Start CI RICE, 100-hp ≤ HP ≤ 300-hp	230 ppmvd CO @ 15% O_2.
Existing, Non-Emergency, Non-Black Start CI RICE, 300-hp < HP ≤ 500-hp	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd or less at 15 percent O2; or b. Reduce CO emissions by 70 percent or more.

All applicable requirements have been incorporated into the permit.

Subpart DDDDD, Industrial, Commercial and Institutional Boilers and Process Heaters. On January 31, 2013, the EPA took final action on its reconsideration of certain issues in the emission standards for the control of HAP from industrial, commercial, and institutional boilers and process heaters at major sources of HAP. The compliance dates for the rule were January 31, 2016, for existing sources and, January 31, 2013, or upon startup, whichever is later, for new sources. A boiler or process heater is new or reconstructed if construction or reconstruction of the boiler or process heater commenced on or after June 4, 2010. There are four heaters one each in EUG 11, EUG 12, EUG 13, and EUG 13B that are considered new for this subpart.

New Boilers/Process Heaters > 10 MMBTUH

EU	Point	Description	MMBTUH	Const. Date
H-2601	P230	HDS Reactor Heater	13.2	2014
H-5602	P61	Hot Oil Heater	20.0	2004
H-6701	P62	Co-Processor Heater	11.8	2006
B-15001	P240	Boiler	285.3	2015

All of the other boilers and heaters listed below are considered existing and have not been reconstructed. Existing boilers and process heaters located at a major source, not including limited use units, must have a one-time energy assessment performed by a qualified energy assessor.

Existing Boilers/Process Heaters > 10 MMBTUH

EU	Point	Description	MMBTUH	Const. Date
B-801	P29	Boiler	72.5	1974
B-802	P30	Boiler	89.8	1975
B-803	P31	Boiler	86.8	1979
H-102A	P32	Process Heater	160.0	Mod. 1998
H-102B	P33	Process Heater	135.0	Mod. 1998
H-103	P34	Process Heater	102.6	1974
H-201	P35	Process Heater	116.7	1974
H-403	P36	Process Heater	98.7	1980
H-404/5	P37	Process Heater	99.3	Mod. 1980
H-601	P38	Process Heater	58.5	1975
H-603	P39	Process Heater	125.5	1992
H-6501	P40	Process Heater	99.7	Mod. 2008
H-6502	P41	Process Heater	54.3	1992
H-15001	P42	Process Heater	326.8	1992
H-101	P43	Process Heater	30.8	Mod. 1998
H-301	P44	Process Heater	21.6	1974
H-401B	P45	Process Heater	14.8	1974
H-406	P46	Process Heater	28.0	1974
H-411	P48	Process Heater	28.0	1986
H-401A	P49	Process Heater	16.0	1969
H-402A	P50	Process Heater	13.9	1970

Existing Boilers/Process Heaters > 10 MMBTUH

EU	Point	Description	MMBTUH	Const. Date
H-402B	P51	Process Heater	15.8	1963
H-901	P52	Process Heater	60.0	1969
H-100024	P54	Asphalt Tank Heater	13.5	1999
H-210001	P55	Process Heater	21.6	1996

Boilers/Process Heaters ≤ 10 MMBTUH

EU	Point	Description	MMBTUH	Const. Date
H-1016	P53	Process Heater	4.8	1954

Most of the affected sources at the facility are considered units designed to burn gas 1 fuels. *Unit(s) designed to burn gas 1 subcategory* includes any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels.

Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity of ≤ 5 MMBTUH must complete a tune-up every 5 years as specified in § 63.7540(a)(12). Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity greater than 5 MMBTUH and less than 10 MMBTUH must complete a tune-up initially and every 2 years as specified in § 63.7540(a)(11). Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity greater than 10 MMBTUH without a continuous oxygen trim system must complete a tune-up annually as specified in § 63.7540(a)(10). Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity greater than 10 MMBTUH with a continuous oxygen trim system that maintains an optimum air to fuel ratio must complete a tune-up every five years as specified in § 63.7540(a)(12). Units in the gas 1 subcategories will conduct these tune-ups as a work practice for all regulated emissions under Subpart DDDDD. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory are not subject to the emission limits in Tables 1 and 2 or 11 through 13 of Subpart DDDDD, or the operating limits in Table 4 of Subpart DDDDD.

Limited-use boilers and process heaters must complete a tune-up every 5 years as specified in § 63.7540(a)(12). They are not subject to the emission limits in Tables 1 and 2 or 11 through 13 of Subpart DDDDD, the annual tune-up, or the energy assessment requirements in Table 3 of Subpart DDDDD, or the operating limits in Table 4 of Subpart DDDDD.

All applicable requirements have been incorporated into the permit.

Subpart GGGGG, Site Remediation. This subpart is applicable to facilities that conduct a site remediation which cleans up a remediation material at a facility that is co-located with one or more other stationary sources that emit HAP and meet the affected source definition. This facility is a major source of HAP and currently conducts site remediation at the facility.

Site remediation at a facility is not subject to this subpart, except for the recordkeeping requirements specified in § 63.7881(c), if the site remediation meets the all of the following conditions:

1. Before beginning the site remediation, you determine that for the remediation material to be excavated, extracted, pumped, or otherwise removed during the site remediation that the total quantity of the HAPs (listed in Table 1 of Subpart GGGGG) is less than 1.10 TPY.
2. The facility prepares and maintains at the facility written documentation to support the determination of the total HAP quantity used to demonstrate compliance with § 63.7881(c)(1). The documentation must include a description of the methodology and data used for determining the total HAPs content of the material.
3. This exemption may be applied to more than one site remediation at the facility provided that the total quantity of the HAPs (listed in Table 1 of Subpart GGGGG) for all of the site remediations exempted under this provision are less than 1.10 TPY.

This facility has documented that all of the site remediations at the facility total less than 1.10 TPY and is only subject to the recordkeeping requirements of this subpart. The RCRA corrective action being performed at the site pursuant to the facility's RCRA Subpart B permit is not subject to Subpart GGGGG.

Subpart LLLLL, Asphalt Processing. This subpart affects asphalt processing and asphalt roofing manufacturing facilities at major sources of HAP. The asphalt processing facility at the refinery is subject to this subpart. Asphalt processing facilities include: asphalt flux blowing stills, asphalt flux storage tanks storing asphalt flux intended for processing in the blowing stills, oxidized asphalt storage tanks, and oxidized asphalt-loading racks. The provisions of 40 CFR Part 60, Subpart J do not apply to emissions from asphalt processing facilities subject to this subpart. This subpart does not apply to any equipment that is subject to the control requirements of 40 CFR Part 63, Subpart CC or to 40 CFR Part 60, Subparts K, Ka, or Kb.

Each blowing still, Group 1 asphalt loading rack, and Group 1 asphalt storage tank at existing, new, and reconstructed asphalt processing facilities are required to meet one of the following requirements:

1. Reduce total hydrocarbon (THC) mass emissions by 95 percent, or to a concentration of 20 ppmv, on a dry basis corrected to 3 percent oxygen;
2. Route the emissions to a combustion device achieving a combustion efficiency of 99.5 percent;
3. Route the emissions to a combustion device that does not use auxiliary fuel achieving a THC destruction efficiency of 95.8 percent;
4. Route the emissions to a boiler or process heater with a design heat input capacity of 44 megawatts (MW) or greater;
5. Introduce the emissions into the flame zone of a boiler or process heater; or
6. Route emissions to a flare meeting the requirements of § 63.11(b).

The Asphalt Blowstill and Thermal Oxidizer (EU HI-801) are subject to the requirements of this subpart. The Asphalt Blowstill is vented to the Thermal Oxidizer and must maintain the three hour average combustion zone temperature at or above the operating limit established during the initial performance test. The refinery has elected to reduce the THC emissions to a concentration of 20 ppmvd @ 3% O_2. The initial performance testing established a relationship between the minimum combustion zone temperature and the asphalt blowstill production rate. The facility has requested an alternative monitoring location for the stack temperature. The facility monitors the temperature in a location upstream of the flame zone rather than in the flame zone to help prevent frequent replacement of the thermocouple. The facility has developed and implemented a site-specific monitoring plan according to the provisions of § 63.8688 (g) and (h).

Asphalt loading rack means the equipment at an asphalt processing facility used to transfer oxidized asphalt from a storage tank into a tank truck, rail car, or barge. Group 1 asphalt loading rack means an asphalt loading rack loading asphalt with a maximum temperature of 500 °F or greater and with a maximum true vapor pressure (MTVP) of 1.5 psia or greater. The Asphalt and No. 6 Fuel Oil Railcar and Truck Loading Racks (EU ASPHALT-RC-LOAD & ASPHALT-TT-LOAD) are considered Group 2 loading racks since they do not load asphalt with a temperature of 500 °F or greater and with a MTVP of 1.5 psia or greater. The facility monitors the temperature of the asphalt processed to the loading racks daily.

Asphalt storage tank means any tank used to store asphalt flux, oxidized asphalt, and modified asphalt, at asphalt roofing manufacturing facilities, petroleum refineries, and asphalt processing facilities. Group 1 asphalt storage tank means an asphalt storage tank that has a capacity of 47,000 gallons of asphalt or greater and stores asphalt at a maximum temperature of 500 °F or greater and has a MTVP of 1.5 psia or greater. The asphalt storage tanks located at the facility store asphalt at temperatures below 500 °F and with MTVP less than 1.5 psia. Group 2 asphalt storage tank means any asphalt storage tank with a capacity of 2.128 Tons (~497 gallons) of asphalt or greater that is not a Group 1 asphalt storage tank. Group 2 asphalt storage vessels are required to limit exhaust gases to 0% opacity. Due to the overlap provisions of NESHAP, Subpart LLLLL, existing sources subject to NSPS, Subpart UU are only required to comply with this NESHAP after May 1, 2006. Therefore, all of the tanks previously subject to NSPS, Subpart UU are now only subject to NESHAP, Subpart LLLLL. The table below lists all Group 2 storage vessels subject to this subpart.

Storage Vessel	Roof Type	Contents	Barrels	Const. Date
T-1102	Cone	Asphalt /Gas Oil	75,786	1975
T-1113	Cone	Gas Oil / Asphalt	131,005	1959
T-1118	Cone	Asphalt	79,742	2012
T-1151	Cone	Asphalt	206,979	1998
T-100149	Cone	Asphalt	35,847	1996
T-100150	Cone	Asphalt	35,847	1996
T-210003	Cone	Asphalt	3,021	1996
T-210004	Cone	Asphalt	6,526	1996
T-210005	Cone	Asphalt	6,526	1996
T-210006	Cone	Polymer Asphalt	10,197	1996
T-210007	Cone	Polymer Asphalt	10,197	1996
T-210008	Cone	Polymer Asphalt	11,715	2001

Storage vessels T-1102, T-1113, T-1118, T-1151, T-100149 and T-100150 are vented to a mist eliminator (EUG 39). Storage vessels T-210003 through T-210008 are vented to a caustic scrubber. The affected facilities must comply with the emission limitations (including operating limits) at all times, except during periods of startup, shutdown, and malfunction, and develop and implement a written startup, shutdown, and malfunction plan (SSMP) and site-specific monitoring plan. All applicable requirements have been incorporated into the permit.

CAM, 40 CFR Part 64 [Applicable]
Compliance Assurance Monitoring (CAM) applies to any pollutant specific EU at a major source, that is required to obtain a Title V permit, if it meets all of the following criteria:

1. It is subject to an emission limit or standard for an applicable regulated air pollutant;
2. It uses a control device to achieve compliance with the applicable emission limit or standard; and
3. It has potential emissions, prior to the control device, of the applicable regulated air pollutant greater than major source levels.

The requirements of this part shall not apply to any of the following emission limitations or standards:

1. Emission limitations or standards proposed by the Administrator after November 15, 1990 pursuant to section 111 or 112 of the Act; and
2. Emission limitations or standards for which a part 70 or 71 permit specifies a continuous compliance determination method, as defined in § 64.1.

Continuous compliance determination method (CCDM) means a method, specified by the applicable standard or an applicable permit condition, which:

1. Is used to determine compliance with an emission limitation or standard on a continuous basis, consistent with the averaging period established for the emission limitation or standard; and
2. Provides data either in units of the standard or correlated directly with the compliance limit.

The following emission units use a control device or are a control device that is used to meet an applicable emission limit or standard:

EU	**Description**	**Pollutant**	**CCDM**
CU Flare	Crude Unit Process Flare	VOC	CPM [1]
HI-801	Asphalt Blowstill Thermal Oxidizer	VOC [4]	CPM [2]
		CO	CPM [2]
HI-81001	West Flare	VOC	CPM [1]
HI-8801	WWTP Incinerator	VOC [4]	CPM [2]
LPLT	LPLT Thermal Oxidizer	VOC [4]	CPM [2]
FGS-200	FCCU Regenerators Flue Gas Scrubber	NO_X	CEM
		CO	CEM
		SO_2	CEM
		PM_{10}	CPM [3]
HI-501	#1 SRU Incinerator	H_2S/SO_2	CEM
Cat_Hop	FCCU Catalyst Hopper Vent Wet Scrubber	PM_{10}	CPM [3]

EU	Description	Pollutant	CCDM
CCR	CCR - H-403, H-404/405	VOC[4]	CPM [2]
H-5601	#2 SRU Incinerator	H_2S/SO_2	CEM
HI-8801	WWTP Incinerator	VOC [4]	CPM [2]
SSP520	Sulfur Storage Pit	H_2S [5]	N/A
MSLA-520	Molten Sulfur Railcar Loading Arm	H_2S [5]	N/A
RCALOAD 900	VOC Railcar Loading Station	VOC [4, 5]	CPM [1]
LPG	LPG Loading Station	VOC [5]	N/A

CPM - Continuous Parameter Monitoring: [1] - Presence of Flare's Pilot light; [2] - Continuous Temperature Monitoring; and [3] - Wet Scrubber Liquid-to-Gas Ratio; [4] – NESHAP; [5] - Less than major source thresholds prior to control.

The EU with CEM are exempt from the requirements of this part. Some of the EU are subject to a NESHAP and are also exempt from this part. The flares use continuous monitoring of the pilot light to ensure compliance with the applicable emission limitations or standards. The FCCU monitors the liquid to gas ratio continuously to ensure compliance with the applicable emission limitations and standards. The permit requires the permittee to continuously monitor the FCCU WS operational parameters established during initial testing (WGS liquid to gas ratio, liquid flow rate, and pressure drop) to ensure compliance with the PM_{10} emission limits.

The WWTP RTO and CAS will be used to comply with NESHAP (Part 61), Subpart FF which was proposed on May 7, 1990, prior to the cutoff date for CAM. The WWTP RTO uses continuous monitoring of the temperature of the combustion zone to ensure compliance with the applicable emission limitations or standards. The WWTP CAS will conduct continuous emission monitoring to comply with the standard.

The compressor engines may use a control device to comply with NSPS, Subpart IIII. However, CAM does not apply to emission limitations or standards proposed by the Administrator after November 15, 1990, pursuant to section 111 or 112 of the Clean Air Act. Therefore, the engines would not be subject to CAM. Also, uncontrolled emissions are less than major source thresholds.

Chemical Accident Prevention Provisions, 40 CFR Part 68 [Applicable]
This facility handles naturally occurring hydrocarbon mixtures at a refinery and the Chemical Accident Prevention Provisions are applicable to this facility. The facility was required to submit the appropriate emergency response plan prior to June 21, 1999. The facility has submitted their plan which was given EPA No. 12005 for EPA Facility No. 1000 00128177. More information on this federal program is available on the web page: *www.epa.gov/rmp*.

Stratospheric Ozone Protection, 40 CFR Part 82 [Subparts A and F are Applicable]
These standards require phase out of Class I & II substances, reductions of emissions of Class I & II substances to the lowest achievable level in all use sectors, and banning use of nonessential products containing ozone-depleting substances (Subparts A & C); control servicing of motor vehicle air conditioners (Subpart B); require Federal agencies to adopt procurement regulations which meet phase out requirements and which maximize the substitution of safe alternatives to Class I and Class II substances (Subpart D); require warning labels on products made with or containing Class I or II substances (Subpart E); maximize the use of recycling and recovery upon disposal (Subpart F); require producers to identify substitutes for ozone-depleting compounds

under the Significant New Alternatives Program (Subpart G); and reduce the emissions of halons (Subpart H).
Subpart A identifies ozone-depleting substances and divides them into two classes. Class I controlled substances are divided into seven groups; the chemicals typically used by the manufacturing industry include carbon tetrachloride (Class I, Group IV) and methyl chloroform (Class I, Group V). A complete phase-out of production of Class I substances is required by January 1, 2000 (January 1, 2002, for methyl chloroform). Class II chemicals, which are hydrochlorofluorocarbons (HCFCs), are generally seen as interim substitutes for Class I CFCs. Class II substances consist of 33 HCFCs. A complete phase-out of Class II substances, scheduled in phases starting by 2002, is required by January 1, 2030.
Subpart F requires that any persons servicing, maintaining, or repairing appliances except for motor vehicle air conditioners; persons disposing of appliances, including motor vehicle air conditioners; refrigerant reclaimers, appliance owners, and manufacturers of appliances and recycling and recovery equipment comply with the standards for recycling and emissions reduction.

The Standard Conditions of the permit address the requirements specified at §82.156 for persons opening appliances for maintenance, service, repair, or disposal; §82.158 for equipment used during the maintenance, service, repair, or disposal of appliances; §82.161 for certification by an approved technician certification program of persons performing maintenance, service, repair, or disposal of appliances; §82.166 for recordkeeping; §82.158 for leak repair requirements; and §82.166 for refrigerant purchase records for appliances normally containing 50 or more pounds of refrigerant.

SECTION IX. TIER CLASSIFICATION, PUBLIC REVIEW, AND FEES

Tier Classification
This permitting action has been determined to be Tier II based on the request for renewal of a Part 70 operating permit. This renewal incorporates a number of modifications that are considered minor modifications as defined in OAC 252:100-8-7.2(b)(1)(A). The Tier determination for each individual project was provided in Section III.

Landowner Notification
The permittee has submitted an affidavit that they are not seeking a permit for land use or for any operation upon land owned by others without their knowledge. The affidavit certifies that the applicant owns the land.

Public Review
The applicant published a “Notice of Filing a Tier II Application” in *The Ardmoreite*, a daily newspaper in Carter County. The notice appeared in the newspaper on May 22, 2019. The notice stated that the application was available for public review at the Ardmore Public Library located at 320 E Street NW, Ardmore, Oklahoma and that the application was also available for public review at the Air Quality Division main office. The applicant will also publish a “Notice of Draft Permit.” The notice will state that the draft permit will be available for public review for a period of 30 days at the Ardmore Public Library and that the draft permit will also be available for public

review at the Air Quality Division main office and on the Air Quality section of the DEQ web page at *http://www.deq.ok.gov*.

State Review
This facility is located within 50 miles of the Oklahoma - Texas Border. The state of Texas will be notified of the draft permit.

EPA Review
The proposed permit will be forwarded to EPA Region VI for a 45-day review period.

Fees Paid
The applicant has submitted the Part 70 source application fees appropriate to the permitting actions requested. A summary of the fees submitted is presented below.

Fees Submitted for Projects Incorporated into this Permit Modification

Permit Number *1	Project Description	Fees Submitted
2012-1523-C (M-2)	The application requested a construction permit to authorize the installation of a new 285.3 MMBTUH boiler. The permit was issued on April 22, 2015.	$5,000
2012-1523-C (M-4)	The application requested a construction permit to incorporate requirements from a consent decree (Civil Action No. SA-05-CA-0569) into the permit. No new emissions units or modifications were authorized by this permitting action. This construction permit provided the basis on which these conditions agreed to in the consent decree may be incorporated into the Title V operating permit.	$5,000
2012-1523-C (M-5)	This permit was issued as an administrative amendment to Permit No. 2012-1523-C (M-4). Valero requested a slight change to the specific condition language to conform with the requirements of the consent decree. The administrative amendment was issued on June 13, 2016.	Not Applicable
2012-1523-TVR (M-6)	Valero requested a minor modification to incorporate an Alternative Monitoring Plan for the Fluidized Catalytic Cracking Unit (FCCU) Flue Gas Scrubber, to incorporate VOC and PM emissions estimates for two existing cooling water towers, to change the classification of a diesel-driven water pump (from an insignificant activity to EUG 40), and to address a number of minor administrative issues (corrections and updates to permit language).	$3,000
2012-1523-C (M-7)	This permit was issued as an administrative amendment to Permit No. 2012-1523-C (M-5). Valero requested a slight change to the specific condition language to conform with the requirements of the consent decree. The administrative amendment was issued on June 30, 2016.	Not Applicable

Fees Submitted for Projects Incorporated into this Permit Modification

Permit Number [*1]	Project Description	Fees Submitted
2012-1523-TVR (M-8)	Valero requested a minor modification to incorporate the requirements for operation of a 600 psig, 285.3 MMBtu/hr steam production boiler into the Title V operating permit. Construction of this emission unit was authorized by Permit No. 2012-1523-C (M-2). This application also requested a number of administrative changes, including the consolidation of multiple leak detection a repair (LDAR) emission units into a single emissions unit under Emission Unit Group (EUG) 31.	$3,000
2012-1523-TVR (M-9)	Valero requested a minor modification to allow an additional cell to an existing cooling tower and to redistribute the loads to two existing cooling towers.	$3,000
2012-1523-AD (M-10)	Valero requested an applicability determination (AD) to confirm that they could rebuild Tank T-1018 under the current permit with or without performing a minor modification to the Title V operating permit. Sufficient fees were submitted to cover the cost of either an AD or a minor modification. The determination was issued on August 11, 2020.	$3,000
2012-1523-TVR (M-11)	Valero requested a minor modification to authorize the replacement of an existing process heater (H-407) with a new steam reboiler which uses steam from an existing 600 pound steam boiler (B-15001).	$3,000
2012-1523-TVR (M-12)	Valero requested a minor modification to authorize the installation of a new emergency generator engine for a new administration building.	$3,000
2012-1523-TVR (M-13)	Valero requested a minor modification to authorize installation of replacement feed filters and a new filter tray in the catalytic feed hydrotreater (CFHT) reactor R-6502 (R-2).	$3,000
2012-1523-TVR (M-14)	Valero requested a minor modification to authorize an increase of the flow rate of supplementary fuel gas to the Alky Flare (EU HI-81002, EUG 14).	$3,000
2019-0630-TVR2	Valero requested renewal of the Title V operating permit.	$7,500

[*1] The project associated with Application No. 2012-1523-TVR (M-3) was cancelled.

SECTION X. SUMMARY

The facility was constructed and is operating as described in the permit application. Ambient air quality standards are not threatened at this site. There are no active Air Quality compliance or enforcement issues that would impact issuance of this operating permit renewal. Issuance of the operating permit is recommended, contingent upon public and EPA review.

The permittee is authorized to operate in conformity with the specifications submitted to Air Quality (AQD) on February 29, 2016, and additional materials submitted after that date. The current Evaluation Memorandum dated May 17, 2022, explains the derivation of applicable permit requirements and estimates of emissions; however, it does not contain operating limitations or permit requirements. As required by applicable state and federal regulations, the permittee is authorized to operate the affected equipment in conformity with the specifications contained herein. Continuing operations under this permit constitutes acceptance of and consent to the conditions contained herein:

1. The permittee shall be authorized to operate the affected facilities noted in this permit continuously (24 hours per day, every day of the year) subject to the following conditions:

[OAC 252:100-8-6(a)(1)]

a. The Crude Unit shall not process fresh feedstock at a rate to exceed 97.1 thousand barrels per day (MBPD) based on a 12-month rolling average.
b. The Fluid Catalytic Cracking Unit (FCCU) shall not process fresh feedstock at a rate to exceed 30 MBPD based on a 12-month rolling average.
c. The Asphalt Blowstill shall not process fresh feedstock at a rate to exceed 12 MBPD based on a 12-month rolling average.
d. The Polymer Modified Asphalt (PMA) Unit shall not produce PMA at a rate to exceed 4,200,000 barrels per year (BPY) based on a 12-month rolling total.
e. The permittee shall determine and record the throughputs of the Crude Unit, FCCU, Asphalt Blowstill, and PMA Unit (daily).
f. To determine compliance with the limits stated above the permittee shall average the daily throughputs recorded during a calendar month and then determine the 12-month rolling average using the monthly average of daily throughputs.

2. Emission limitations and standards for affected Emission Units (EU):

STORAGE VESSELS (EUG 1-8)

a. Storage Vessel Emissions
   i. VOC emissions from all of the storage vessels in EUG 1 through 8 shall not exceed 185.6 tons in any 12 month period. [OAC 252:100-8-6(a)(1)]
   ii. The permittee shall record the throughput of each storage vessel at least monthly and determine, using the methods specified in § 63.641, and record the maximum true vapor pressure (MTVP) of the material stored during the respective storage period. [OAC 252:100-8-6(a)(3)(A) & 100-43]
   iii. To demonstrate compliance with the emission limits, the permittee shall calculate the emissions from the storage vessels using the storage vessels' throughputs, the associated vapor pressures and the most recent version of EPA Tanks or other applicable program. Compliance with the TPY limits shall be based on a 12-month rolling total and calculated monthly. [OAC 252:100-8-6(a)(3)(A) & 100-43]

EUG 1A External Floating Roof (EFR), Group 1 Storage Vessels Subject to NESHAP, Part 63, Subpart CC: EU T-1019, T-1082, T-1083, T-1084, T-1115, T-1116, T-1123, T-1124, T-1125, T-1126, T-1130, T-1131, and T-1132.

EU	Point	Roof Type	Barrels
T-1019	F2	External Floating	66,868
T-1082	F3	External Floating	124,714
T-1083	F4	External Floating	124,714
T-1084	F5	External Floating	124,714
T-1115	F6	External Floating	27,205
T-1116	F7	External Floating	27,315
T-1123	F8	External Floating	60,766
T-1124	F9	External Floating	111,721
T-1125	F10	External Floating	124,398
T-1126	F11	External Floating	124,412
T-1130	F12	External Floating	79,414
T-1131	F13	External Floating	125,100
T-1132	F14	External Floating	80,138

a. The permittee shall comply with NESHAP, 40 CFR Part 63, Subpart CC for each affected storage vessel including but not limited to: [40 CFR §§ 63.640-656]
   i. § 63.642 General Standards
   ii. § 63.646 Storage Vessel Provisions
   iii. § 63.655 Reporting and Recordkeeping Requirements

EUG 1B External Floating Roof (EFR), Group 1 Storage Vessels Subject to NSPS, Part 60, Subpart Kb and NESHAP, Part 63, Subpart CC: EU T-1018R.

EU	Point	Roof Type	Barrels
T-1018R	F1	External Floating	62,850

a. The permittee shall comply with NESHAP, 40 CFR Part 63, Subpart CC for each affected storage vessel including but not limited to: [40 CFR §§ 63.640-656]
   i. § 63.642 General Standards
   ii. § 63.646 Storage Vessel Provisions
   iii. § 63.655 Reporting and Recordkeeping Requirements
b. The permittee shall comply with NSPS, 40 CFR Part 60, Subpart Kb for each affected storage vessel including but not limited to: [40 CFR §§ 60.110b-117b]
   i. § 60.112b Standard for VOC;
   ii. § 60.113b Testing and procedures;
   iii. § 60.115b Reporting and recordkeeping requirements; and
   iv. § 60.116b Monitoring of operations.

EUG 2 Cone Roof (CR), Group 2 Storage Vessels Subject to NESHAP, Part 63, Subpart CC and NSPS, Subpart Kb: EU T-1121, T-1127, T-1128, T-1129, TK-13006, T-153, T-156, T-1141, T-1142, T-5801, and TK-90002.

EU	Point	Roof Type	Barrels	Applicable Subpart
T-1121	P3	Cone	40,526	Kb
T-1127	P4	Cone	80,579	CC
T-1128	P5	Cone	80,574	Kb
T-1129	P6	Cone	2,113	CC
T-1141	P8	Cone	119,189	Kb
T-1142	P9	Cone	79,445	Kb
T-1153	P10	Cone	200,676	Kb
T-1156	P11	Cone	56,000	Kb
T-5801	P12	Cone	895	Kb
TK-13006	P13	Cone	485	CC
TK-90002	P14	Cone	630	Kb

a. The permittee shall comply with NESHAP, 40 CFR Part 63, Subpart CC for the affected storage vessels, as noted, including but not limited to: [40 CFR §§ 63.640-656]
   i. § 63.655 Reporting and Recordkeeping Requirements – (i)(1) [§ 63.123(a)] & (i)(1)(iv).
b. The permittee shall comply with NSPS, 40 CFR Part 60, Subpart Kb for the affected storage vessels, as noted, including but not limited to: [40 CFR §§ 60.110b-117b]
   i. § 60.116b Monitoring of Operations – (a) & (b).
c. Storage vessels with a capacity greater than or equal to 950 barrels shall not store a VOL with a MTVP greater than or equal to 0.5076 psia. All other storage vessels shall not store a VOC with VP greater than or equal to 1.5 psia under actual storage conditions. To

demonstrate compliance with the vapor pressure limits, the permittee shall determine the MTVP and VP, using the methods specified in § 60.111b, and maintain a record of the MTVP or VP of the material stored in these storage vessels.

[OAC 252:100-8-6(a)(1), 100-8-6(a)(3), 100-37, & 100-43]

d. The temperature of the gas oil stored in Storage Vessel T-1153 shall not equal or exceed 200 ºF. To demonstrate compliance with the temperature limit, the permittee shall measure and record at least daily the temperature of the liquid in the storage vessel.

[OAC 252:100-8-6(a)(1), 100-8-6(a)(3), & 100-43]

e. The temperature of the slurry stored in Storage Vessel T-1156 shall not equal or exceed 400 ºF. To demonstrate compliance with the temperature limit, the permittee shall measure and record at least daily the temperature of the liquid in the storage vessel.

[OAC 252:100-8-6(a)(1), 100-8-6(a)(3), & 100-43]

EUG 3 EFR & IFR, Group 1 & 2 Storage Vessel Subject to NSPS, Part 60, Subpart Kb: EU T-1155, T-1152, and T-100160.

EU	Point	Roof Type	Barrels
T-1155	F15	External Floating	163,555
T-1152	F16	External Floating	11,890
T-100160	P18	Internal Floating	14,000

c. The permittee shall comply with NSPS, 40 CFR Part 60, Subpart Kb for the affected storage vessel including but not limited to: [40 CFR §§ 60.110b-117b]

i. § 60.112b Standard for VOC;
ii. § 60.113b Testing and procedures;
iii. § 60.115b Reporting and recordkeeping requirements; and
iv. § 60.116b Monitoring of operations.

EUG 5 CR, Group 2 Storage Vessels Subject to NESHAP, Part 63, Subpart LLLLL: EU T-1102, T-1113, T-1118, T-1151, T-100149, T-100150, and the group of tanks associated with EU P-26 (T-210003, T-210004, T-210005, T-210006, T-210007, and T-210008).

EU	Tank	Point	Roof Type	Barrels
T-1102	T-1102	P19	Cone	75,786
T-1113	T-1113	P21	Cone	131,005
T-1118	T-1118	P22	Cone	79,742
T-1151	T-1151	P23	Cone	206,979
T-100149	T-100149	P24	Cone	35,847
T-100150	T-100150	P25	Cone	35,847
P-26 (includes the group of tanks indicated, which are configured to allow liquids to flow freely between the tanks and which have vent lines from	T-210003	P186	Cone	3,021
	T-210004		Cone	6,526
	T-210005		Cone	6,526
	T-210006		Cone	10,197
	T-210007		Cone	10,197

EU	Tank	Point	Roof Type	Barrels
each tank tied into a common manifold that routes vapors to the V-210001 PMA Vent Gas Scrubber, P-26)	T-210008		Cone	11,715

a. The permittee shall comply with NESHAP, 40 CFR Part 63, Subpart LLLLL for the affected storage vessels including but not limited to: [40 CFR §§ 63.8680-8698]
   i. §63.8680 What is the purpose of this subpart?
   ii. §63.8681 Am I subject to this subpart? (a-f)
   iii. §63.8682 What parts of my plant does this subpart cover? (a-e)
   iv. §63.8683 When must I comply with this subpart? (b & d)
   v. §63.8684 What emission limitations must I meet? (a)
   vi. §63.8685 What are my general requirements for complying with this subpart? (a-d)
   vii. §63.8686 By what date must I conduct performance tests or other initial compliance demonstrations? (a & b)
   viii. §63.8687 What performance tests, design evaluations, and other procedures must I use? (a-e)
   ix. §63.8688 What are my monitoring installation, operation, and maintenance requirements?
   x. §63.8689 How do I demonstrate initial compliance with the emission limitations? (a-c)
   xi. §63.8692 What notifications must I submit and when? (a-f)
   xii. §63.8693 What reports must I submit and when? (a-f)
   xiii. §63.8694 What records must I keep? (a & b)
   xiv. §63.8695 In what form and how long must I keep my records? (a-c)
   xv. §63.8696 What parts of the General Provisions apply to me?

EUG 6 Oil-Water Separators Subject to NESHAP, Part 63, Subpart CC and Part 61, Subpart FF and OAC 252:100-37: EU V-8801 and V-8802.

EU	Point	Roof Type	Contents	Barrels
V-8801	F17	External Floating	Oil / Water	17,200
V-8802	F18	External Floating	Oil / Water	17,200

a. The permittee shall comply with the applicable sections of NESHAP, 40 CFR Part 63, Subpart CC, Wastewater Provisions of § 63.647 for the Oil-Water Separators (V-8801 and V-8802) including but not limited to: [40 CFR 63.640-654]
   i. The permittee shall comply with the requirements of § 61.340 through § 61.355 of 40 CFR Part 61, Subpart FF. [§ 63.647(a)]
      A. The Oil-Water Separators (V-8801 and V-8802) shall comply with the Alternative Standards for Oil-Water Separators of 40 CFR § 61.352 and § 60.693-2(a). [§ 61.352 (a)(1)]

b. The cover shall rest on the surface of the contents and be equipped with a closure seal, or seals, to close the space between the cover edge and container wall. All gauging and sampling devices shall be gas-tight except when gauging or sampling is taking place. The oil removal devices shall be gas-tight except when manual skimming, inspection and/or repair is in progress. [OAC 252:100-37-37(2)]

EUG 7 CR, Storage Vessel Subject to NSPS, 40 CFR Part 60, Subpart Kb and Subpart QQQ: EU T-83001.

EU	Point	Roof Type	Contents	Barrels
T-83001	P32	Cone	Sour Water	18,885

a. The permittee shall comply with NSPS, 40 CFR Part 60, Subpart Kb for the affected storage vessels including but not limited to: [40 CFR 60.110b-117b]
   i. § 60.116b Monitoring of Operations – (a) & (b).
b. EU T-83001 shall be operated with a barrier of diesel fluid. [OAC 252:100-8-6(a)(1)]
c. EU T-83001 shall comply with the requirements of NSPS, 40 CFR Part 60, Subpart QQQ for the affected storage vessel including but not limited to: [40 CFR 60.690-698]
   i. § 60.692-3 Standards: Oil-water separators.

EUG 8 CR, Storage Vessel Subject to OAC 252:100-31: EU T-5602.

EU	Point	Roof Type	Contents	Barrels
T-5602	P33	Cone	Sulfur	3,644

a. EU TK-5602 shall be vented to the SRU incinerator or the input of the SRU at all times. [OAC 252:100-31-26]
b. EU TK-5602 is subject to OAC 252:100-31-26 and shall comply with all applicable provisions including but not limited to:
   i. H_2S contained in the waste gas stream from any petroleum or natural gas process equipment shall be reduced by 95% by removal or by being oxidized to SO_2 prior to being emitted to the ambient air. [OAC 252:100-31-26(1)(A)]
   ii. The owner or operator shall install, maintain, and operate an alarm system that will signal a malfunction for all thermal devices used to control H_2S emissions from petroleum and natural gas processing facilities regulated under OAC 252:100-31-26(1). [OAC 252:100-31-26(1)(B)]

COMBUSTION UNITS (EUG 9-13)

EUG 9 Combustion Units Subject to NSPS, Subpart J & OAC 252:100-19, 33, and 8-34 (as identified): EU B-801, B-802, B-803, H-102A, H-102B, H-103, H-201, H-403, H-404/5, H-601, H-603, H-6502, and H-15001.

EU	Point	Description	MMBTUH
B-801	P34	Boiler	72.5

EU	Point	Description	MMBTUH
B-802	P35	Boiler	89.8
B-803	P36	Boiler	86.8
H-102A	P37	Process Heater	160.0
H-102B	P38	Process Heater	135.0
H-103	P39	Process Heater	102.6
H-201	P40	Process Heater	116.7
H-403	P41	Process Heater	98.7
H-404/5	P42	Process Heater	99.3
H-601	P43	Process Heater	58.5
H-603	P44	Process Heater	125.5
H-6502	P45	Process Heater	54.3
H-15001	P46	Process Heater	326.8

a. EU B-801, B-802, B-803, H-102A, H-102B, H-103, H-201, H-403, H-404/5, H-601, H-603, H-6502, and H-15001 are subject to NSPS, Subpart J and shall comply with all applicable provisions including but not limited to: [40 CFR §§ 60.100-109]
   i. § 60.104 Standards for sulfur dioxide – (a)(1)
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
   iii. § 60.106 Test methods and procedures – (e)

b. These EU shall only combust natural gas or fuel gas as defined in § 60.101(d). [OAC 252:100-19-4]

c. Emissions of NO_X from the affected EU shall not exceed 0.2 lb/MMBTU, three hour average. [OAC 252:100-33-2(a)(1)]

d. EU B-801, B-802, B-803, H-103, H-403, H-404/5, and H-601 shall not exceed the following limit: [OAC 252:100-8-6(a)(1)]
   i. NO_X - 0.098 lb/MMBTU, three hour average;

e. EU H-201 shall not exceed the following limit: [OAC 252:100-8-6(a)(1)]
   i. NO_X - 0.186 lb/MMBTU, three hour average;

f. EU H-603, H-6502, and H-15001 shall be operated with Low-NO_X burners (LNB) and emissions shall not exceed the following limits:
   i. EU H-603: NO_X - 0.066 lb/MMBTU, three hour average;
      CO - 0.0415 lb/MMBTU, 12-month rolling average;
   ii. EU H-6502: NO_X - 0.060 lb/MMBTU, three hour average;
      CO - 0.0404 lb/MMBTU, 12-month rolling average;
   iii. EU H-15001: NO_X - 0.060 lb/MMBTU, three hour average;
      CO - 0.030 lb/MMBTU, 12-month rolling average;

   [OAC 252:100-8-34(b) & Permit No. 98-172-C (M-20) PSD]

g. EU H-102A and H-102B shall be equipped with low-NO_X burners (LNB) and emissions shall be monitored as follows:

   [OAC 252:100-8-34(b), Permit No. 98-172-C (M-20) PSD, & Permit No. 2012-1523-C (M-7)]

   i. H-102A and H-102B shall be equipped with NO_X and O_2 CEMS. With respect to the NO_X and O_2 CEMS, the source shall install, certify, calibrate, maintain and operate them in accordance with the provisions of 40 CFR §60.13 which are applicable only to CEMS (excluding those provisions applicable only to continuous opacity monitoring systems) and Part 60, Appendices A and F, and the applicable performance specification test of 40 CFR Part 60, Appendix B. With respect to 40 CFR Part 60 Appendix F, in lieu of the requirements of 40 CFR Part 60, Appendix F §§5.1.1, 5.1.3 and 5.1.4, the source must conduct either a RAA or a RATA on each CEMS at least once every three (3) years. The source must also conduct CGA each calendar quarter during which a RAA or a RATA is not performed.

ii. EU H-102A: NO_X emissions shall not exceed 0.045 lb/MMBTU, three hour average;
iii. EU H-102B: NO_X emissions shall not exceed 0.045 lb/MMBTU, three hour average;
iv. EU H-102A: NO_X emissions shall not exceed 0.045 lb/MMBTU on a 365-day rolling average;
v. EU H-102B: NO_X emissions shall not exceed 0.045 lb/MMBTU on a 365-day rolling average;

EUG 10 Combustion Unit Subject to NSPS, Subpart Ja & OAC 252:100-19, 33, and 8-34 (as identified): EU H-6501.

EU	**Point**	**Description**	**MMBTUH**
H-6501	P47	Process Heater	99.7

a. EU H-6501 is subject to NSPS, Subpart Ja and shall comply with all applicable provisions of NSPS, Subpart Ja including but not limited to: [40 CFR §§ 60.100a-109a]
   i. § 60.102a Emissions limitations – (g)(1);
   ii. § 60.103a Work practice standards;
   iii. § 60.104a Performance tests;
   iv. § 60.107a Monitoring of emissions and operations for process heaters and other fuel gas combustion devices; and
   v. § 60.108a Recordkeeping and reporting requirements.

b. This EU shall only combust natural gas or fuel gas as defined in § 60.101(d).
[OAC 252:100-19-4]

c. Emissions of NO_X from the affected EU shall not exceed 0.2 lb/MMBTU, three hour average.
[OAC 252:100-33-2(a)(1)]

d. EU H-6501 shall be operated with Low-NO_X burners (LNB) and emissions shall not exceed the following limits:
   i. EU H-6501: NO_X - 0.040 lb/MMBTU, three hour average;
   CO - 0.0404 lb/MMBTU, 12-month rolling average;
[OAC 252:100-8-34(b) & Permit No. 98-172-C (M-20) PSD]

EUG 11 Combustion Units Subject to NSPS, Subpart J & OAC 252:100-19: EU H-101, H-301, H-401A, H-401B, H-402A, H-402B, H-406, H-411, H-901, H-1016, and H-6701.

EU	**Point**	**Description**	**MMBTUH**
H-101	P48	Process Heater	30.8
H-301	P49	Process Heater	21.6
H-401A	P50	Process Heater	16.0

EU	Point	Description	MMBTUH
H-401B	P51	Process Heater	14.8
H-402A	P52	Process Heater	13.9
H-402B	P53	Process Heater	15.8
H-406	P54	Process Heater	28.0
H-411	P56	Process Heater	28.0
H-901	P57	Process Heater	60.0
H-1016	P58	Process Heater	4.8
H-6701	P62	Co-Processor Heater	11.8

a. EU H-101, H-301, H-401A, H-401B, H-402A, H-402B, H-406, H-411, H-901, H-1016, and H-6701 are subject to NSPS, Subpart J and shall comply with all applicable provisions including but not limited to: [40 CFR §§ 60.100-109]
   i. § 60.104 Standards for sulfur dioxide – (a)(1)
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
   iii. § 60.106 Test methods and procedures – (e)

b. EU H-101, H-301, H-401A, H-401B, H-402A, H-402B, H-406, H-411, H-901, and H-1016 shall not exceed the following limit: [OAC 252:100-8-6(a)(1)]
   i. NO_X - 0.098 lb/MMBTU, three hour average;

c. EU H-6701 shall be equipped and operated with LNB and emissions of NO_X shall not exceed 0.06 lb/MMBTU, 12-month rolling average. [Permit No. 98-172-C (M-20) PSD]

d. These EU shall only combust natural gas or fuel gas as defined in § 60.101(d). [OAC 252:100-19-4]

EUG 12 Combustion Units Subject to NSPS, Subparts Dc & J & OAC 252:100-19: EU H-100024, H-210001, and H-5602.

EU	Point	Description	MMBTUH
H-100024	P59	Asphalt Tank Heater	13.5
H-210001	P60	Process Heater	12.2
H-5602	P61	Hot Oil Heater	20.0

a. These EU are subject to NSPS, Subpart Dc and shall comply with all applicable requirements including but not limited to: [40 CFR §§ 60.40c-48c]
   i. The permittee shall record and maintain records of the fuels combusted in each affected EU during each calendar month. [40 CFR 60.48c(g)]

b. These EU are subject to NSPS, Subpart J and shall comply with all applicable provisions including but not limited to: [40 CFR §§ 60.100-109]
   i. § 60.104 Standards for sulfur dioxide – (a)(1)
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
   iii. § 60.106 Test methods and procedures – (e)

c. EU H-210001 shall only be fired with commercial grade natural gas. [OAC 252:100-31-25(1)(A) & 100-19-4]

d. EU H-5602 shall be equipped and operated with LNB and emissions of NO_X shall not exceed 0.05 lb/MMBTU, 12-month rolling average. [Permit No. 98-172-C (M-20) PSD]

EUG 13 Combustion Unit Subject to NSPS, Subpart Ja and OAC 252:100-19: EU H-2601.

EU	Point	Description	MMBTUH
H-2601	P230	HDS Reactor Heater	13.2

a. EU H-2601 is subject to NSPS, Subpart Ja and shall comply with all applicable provisions of NSPS, Subpart Ja including but not limited to: [40 CFR §§ 60.100a-109a]
   i. § 60.102a Emissions limitations – (g)(1);
   ii. § 60.103a Work practice standards;
   iii. § 60.104a Performance tests;
   iv. § 60.107a Monitoring of emissions and operations for process heaters and other fuel gas combustion devices; and
   v. § 60.108a Recordkeeping and reporting requirements.

b. This EU shall only combust natural gas or fuel gas as defined in § 60.101(d). [OAC 252:100-19-4]

c. EU H-2601 shall be equipped and operated with LNB and emissions of NO_X shall not exceed 0.06 lb/MMBTU, 12-month rolling average. [OAC 252:100-8-30(b)(4)]

EUG 13B Combustion Unit Subject to NSPS, Subparts Db and Ja and OAC 252:100-19 and 33: EU B-15001.

EU	Point	Description	MMBTUH
B-15001	P240	Boiler	285.3

Emission limits and standards for EU B-15001:
[40 CFR § 60.44b and OAC 252:100-8-30(b)(4)]

Emission Limits		Averaging Period
Nitrogen Oxide (Expressed as NO_2) [1]	0.1 lb/MMBtu	30-day rolling average
	35.01 TPY	12-month rolling total
Carbon Monoxide [1]	12.84 lb/hr	3-hour average

[1] These limits apply at all times, including periods of startup, shutdown, or malfunction.

a. EU B-15001 is subject to NSPS, Subpart Db and shall comply with all applicable provisions of NSPS, Subpart Db including but not limited to: [40 CFR §§ 60.40b-49b]
   i. § 60.40b Applicability and delegation of authority;
   ii. § 60.41b Definitions;
   iii. § 60.44b Standard for nitrogen oxides (NO_X);
   iv. § 60.46b Compliance and performance test methods and procedures for particulate matter and nitrogen oxides;
   v. §60.48b Emission monitoring for particulate matter and nitrogen oxides; and
   vi. §60.49b Reporting and recordkeeping requirements.

b. EU B-15001 is subject to NSPS, Subpart Ja and shall comply with all applicable provisions of NSPS, Subpart Ja including but not limited to: [40 CFR §§ 60.100a-109a]
   i. § 60.102a Emissions limitations – (g)(1);
   ii. § 60.103a Work practice standards;
   iii. § 60.104a Performance tests;
   iv. § 60.107a Monitoring of emissions and operations for process heaters and other fuel gas combustion devices; and
   v. § 60.108a Recordkeeping and reporting requirements.

c. This EU shall only combust natural gas or fuel gas as defined in § 60.101(d). [OAC 252:100-19-4]

d. EU B-15001 shall be equipped and operated with Ultra-Low NO_X Burners and emissions of NO_X shall not exceed the limits shown above. [OAC 252:100-8-30(b)(4)]
   i. In addition to computing and recording 30-day rolling average NO_X emissions (lb/MMBtu) in accordance with NSPS, Subpart Db, the permittee shall compute and record 12-month rolling total NO_X emissions (TPY). The 12-month rolling total NO_X emissions shall be computed using lb/MMBtu values gathered on an hourly basis (or lb/MMBtu values gathered more frequently).
   ii. The permittee shall record fuel consumption (MMBtu) on an hourly basis (or more frequently).

e. EU B-15001 shall be equipped with a continuous emissions monitoring system (CEMS) for determining and recording NO_X emissions. The CEMS shall meet the applicable performance specifications of 40 CFR Part 60, Appendix B and 40 CFR § 60.48b. [OAC 252:100-8-6(a)(3) & 100-43 and 40 CFR §§ 60.40b-49b]

OTHER EMISSION UNITS

EUG 14 Flares Subject to NSPS, Subparts A & Ja and NESHAP, Subpart A: HI-81001, HI-81002, and HI-81003.

EU	Point	Description
HI-81001	P63	West Flare – 42” SASFF
HI-81002	P64	HF Process Gas Flare – 20” SASFF
HI-81003	P65	East Flare – 24” SASFF

Emission limits and standards for the affected EU:

	NO_X		CO		VOC		PM_{10}	
EU	**lb/hr[1]**	**TPY**	**lb/hr[1]**	**TPY**	**lb/hr[1]**	**TPY**	**lb/hr[1]**	**TPY**
HI-81001	20.4	8.3	111.0	45.4	42.0	17.2	2.8	0.9
HI-81002	28.2	11.0	153.2	60.1	58.0	22.7	3.9	1.5
HI-81003	20.4	8.0	111.0	43.8	42.0	16.6	2.8	1.1

1 - Three hour average.

a. EU HI-81001, HI-81002, and HI-81003 are subject to NSPS, Subpart Ja and shall comply with all applicable provisions of NSPS, Subpart Ja including but not limited to:

[40 CFR §§ 60.100a-109a]

i. § 60.102a Emissions limitations;
ii. § 60.103a Work practice standards;
iii. § 60.104a Performance tests;
iv. § 60.107a Monitoring of emissions and operations for process heaters and other fuel gas combustion devices; and
v. § 60.108a Recordkeeping and reporting requirements.

b. EU HI-81001, HI-81002, and HI-81003 shall comply with all applicable requirements including but not limited to the following requirements: [40 CFR Parts 60 and 63]
i. The flare shall meet the design requirements of 40 CFR Part 60 NSPS, Subpart A; or
ii. The flare shall meet the design requirements of 40 CFR Part 63 NESHAP, Subpart A.

c. Compliance with the emission limitations shall be based on the maximum rated capacity (HHV), the respective emissions factors from AP-42 (1/95), Section 13.5.
[OAC 252:100-8-6(a)(3) & 100-43]

EUG 15 Sulfur Recovery Units' (SRU) Incinerators Subject to NSPS, Subpart J, NESHAP, Subpart UUU, & OAC 252:100-31: EU HI-501 & HI-5602.

EU	Point	Description
HI-501	P66	#1 SRU Incinerator
HI-5602	P67	#2 SRU Incinerator

Emission limits and standards for the affected EU:

	NO_X		SO_2	
EU	**lb/hr [1]**	**TPY**	**lb/hr [2]**	**TPY**
HI-501	2.0	8.5	12.0	52.5
HI-5602	4.0	17.4	26.2	114.7

1 – three hour average.
2 – two hour average of contiguous 1-hour averages.

a. Each SRU (EU HI-501 and HI-5602) shall be equipped with a tail gas-treating unit (TGTU). The TGTU shall process the off-gases from the SRU.
[OAC 252:100-8-34(b) & Permit No. 98-172-C (M-20) PSD]

b. The SRU (EU HI-501 and HI-5602) are subject to NSPS, Subpart J and shall comply with all applicable provisions including but not limited to: [40 CFR §§ 60.100-109]
i. § 60.104 Standards for sulfur dioxide – (a)(2)(i);
ii. § 60.105 Monitoring of operations – (a)(5)(i & ii) & (e)(4)(i) or other alternative monitoring approved per § 60.13;
iii. § 60.106 Test methods and procedures – (a) & (f)(1 & 3).

c. The SRU (EU HI-501 and HI-5602) are subject to NESHAP, Subpart UUU and shall comply with all applicable provisions by the dates specified in § 63.1563(b) including but not limited to: [40 CFR §§ 63.1560-1579]
i. § 63.1568 What are my requirements for HAP emissions from sulfur recovery units? – (a)(1), (b)(1, 3, 4, 5, 6, & 7), & (c)(1 & 2);

ii. § 63.1569 What are my requirements for HAP emissions from bypass lines? – (a)(1 & 3), (b)(1-4), & (c)(1 & 2);
iii. § 63.1570 What are my general requirements for complying with this subpart? – (a) & (c-g);
iv. § 63.1571 How and when do I conduct a performance test or other initial compliance demonstration? – (a) & (b)(1-5);
v. § 63.1572 What are my monitoring installation, operation, and maintenance requirements? – (a)(1-4) & (d)(1-2);
vi. § 63.1574 What notifications must I submit and when? – (a)(2) & (f)(1, 2(i), 2(ii), 2(viii), 2(ix), & 2(x));
vii. § 63.1575 What reports must I submit and when? – (a-h);
viii. § 63.1576 What records must I keep, in what form, and for how long? – (a), (b)(1, 3, 4, 5), & (d-i);
ix. § 63.1577 What parts of the General Provisions apply to me?

d. The SRU (EU HI-501 and HI-5602) are subject to OAC 252:100-31-26 and shall comply with all applicable provisions including but not limited to:
   i. H_2S contained in the waste gas stream from any petroleum or natural gas process equipment shall be reduced by 95% by removal or by being oxidized to SO_2 prior to being emitted to the ambient air. [OAC 252:100-31-26(1)(A)]
   ii. The owner or operator shall install, maintain, and operate an alarm system that will signal a malfunction for all thermal devices used to control H_2S emissions from petroleum and natural gas processing facilities regulated under OAC 252:100-31-26(1). [OAC 252:100-31-26(1)(B)]
   iii. Sulfur recovery plants operating in conjunction with any refinery process shall have the sulfur reduction efficiencies required below. [OAC 252:100-31-26(2)(B)]
      A. When the sulfur content of the acid gas stream from the refinery process is greater than 5.0 LT/D but less than or equal to 150.0 LT/D, the daily required sulfur dioxide emission reduction efficiency of the sulfur recovery plant shall be calculated using the following formula, where Z is the minimum emission reduction efficiency required at all times and X is the sulfur feed rate expressed in LT/D of sulfur rounded to one decimal place: $Z = 92.34 (X^{0.00774})$.
[OAC 252:100-31-26(2)(D)]

e. Compliance with the emission limitations shall be based on the following: #1 SRU Incinerator - NO_X: the amount of auxiliary fuel (MMBTU) and waste gas (SCF), the heat content of the waste gas (BTU/SCF), and AP-42 (7/98), Section 1.4 or performance test data; SO_2 - the flow rate of the SRU and the CEM data; #2 SRU Incinerator - NO_X: the amount of auxiliary fuel (MMBTU) and waste gas (SCF), the heat content of the waste gas (BTU/SCF), and AP-42 (7/98), Section 1.4 or performance test data; SO_2 - the flow rate of the SRU and the CEM data. Compliance with the TPY limits shall be based on a 12-month rolling total and calculated monthly. [OAC 252:100-8-6(a)(3) & 100-43]

f. Emissions from the MEROX disulfide settler (V-732) shall be vented to HI-501 or to HI-801. [OAC 252:100-8-6(a)(1)]

EUG 16 Asphalt Blowstill Incinerator Subject to NSPS, Subparts A & J, NESHAP, Subparts A, CC, & LLLLL: EU HI-801.

EU	**Point**	**Description**
HI-801	P68	Asphalt Blowstill Incinerator

Emission limits and standards for the affected EU:

	NO_X		**CO**		**SO_2**	
EU	**lb/hr[1]**	**TPY**	**lb/hr[1]**	**TPY**	**lb/hr[1]**	**TPY**
HI-801	9.4	41.1	6.7	22.5	8.0	35.0

[1] - three hour average.

a. EU HI-801 is subject to NSPS, Subpart J and shall comply with all applicable provisions including but not limited to: [40 CFR §§ 60.100-109]
   i. § 60.104 Standards for sulfur dioxide – (a)(1)
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii) or other alternative monitoring approved per § 60.13.
   iii. § 60.106 Test methods and procedures – (e)

b. EU HI-801 is subject to NESHAP, 40 CFR Part 63, Subpart CC and shall comply with the applicable sections for each affected component including but not limited to: [40 CFR §§ 63.640-659]
   i. § 63.642 General Standards - (c-g), (i), (k), & (l);
   ii. § 63.643 Miscellaneous process vent provisions - (a & b);
   iii. § 63.644 Monitoring provisions for miscellaneous process vents - (a - e);
   iv. § 63.645 Test methods and procedures for miscellaneous process vents - (a-h);
   v. § 63.652 Emissions averaging provisions;
   vi. § 63.653 Monitoring, recordkeeping, and implementation plan for emissions averaging;
   vii. § 63.655 Reporting and Recordkeeping Requirements - (e-i).

c. EU HI-801 is subject to NESHAP, Subpart LLLLL and shall comply with all applicable provisions including but not limited to: [40 CFR §§ 63.8680-8698]
   i. § 63.8681 Am I subject to this subpart? (a-c) & (e)
   ii. § 63.8682 What parts of my plant does this subpart cover? (a), (b)(1), & (e)
   iii. § 63.8683 When must I comply with this subpart? (b)
   iv. § 63.8684 What emission limitations must I meet? (a-b)
   v. § 63.8685 What are my general requirements for complying with this subpart? (a-d)
   vi. § 63.8688 What are my monitoring installation, operation, and maintenance requirements? (a)(1-3), (b)(1-6), (e), & (g)(1-3), & (h-j)
   vii. § 63.8689 How do I demonstrate initial compliance with the emission limitations? (a-c)
   viii. § 63.8690 How do I monitor and collect data to demonstrate continuous compliance? (a-c)
   ix. § 63.8691 How do I demonstrate continuous compliance with the operating limits? (a-d)
   x. § 63.8692 What notifications must I submit and when? (a-f)

xi. § 63.8693 What reports must I submit and when? (a-f)
xii. § 63.8694 What records must I keep? (a-d)
xiii. § 63.8695 In what form and how long must I keep my records? (a-c)
xiv. § 63.8696 What parts of the General Provisions apply to me?

d. All off-gases from the asphalt blowstill shall be either combusted by a properly operated and maintained incinerator (i.e., operated at a 3-hour average combustion zone temperature greater than 1,260°F), routed to the fuel gas recovery system, or routed to the #1 SRU. [OAC 252:100-8-6(a)(1)]

e. The stack flue gas temperature of the incinerator of EU HI-801 shall not drop below 1,260 °F based on a three hour average, during periods in which V-732 is venting to HI-801 and while the incinerator is used to control emissions from any of the following: the asphalt blowstill, the MEROX De-Sulfide Settler (V-732), or the Alkylate/Gasoline Railcar Loading Station (RCALOAD 900). [OAC 252:100-8-6(a)(1)]

f. The permittee shall monitor and record the temperature at the stack of the incinerator of EU HI-801 (daily). [OAC 252:100-8-6(a)(3) & 100-43]

g. EU HI-801 shall not process more than 21,287 lb/hr (monthly average) of waste gas as determined by site-specific parametric association of waste-gas generation as a function of the air flow rate into the asphalt blowing process. [OAC 252:100-8-6(a)(1)]

h. The permittee shall determine and record the supplemental fuel flow and the amount of waste gas generated from the asphalt blowstill per barrel of asphalt (quarterly). [OAC 252:100-8-6(a)(3) & 100-43]

i. Compliance with the emission limitations shall be based on the following: for NO_X and CO - the supplemental fuel flow (MMBTUH (HHV)), the waste gas flow rate (lb/hr) and heat content (BTU/lb), and the emissions factors from AP-42 (7/98), Section 1.4 or performance test data; NO_X emissions shall include the waste gas nitrogen content (ppmvd); for SO_2 - the flow rate (SCFH) and the H_2S concentration (gr/DSCF). Compliance with the TPY limits shall be based on a 12-month rolling total and shall be calculated monthly. [OAC 252:100-8-6(a)(3) & 100-43]

j. Emissions from the MEROX disulfide settler (V-732) shall be vented to EU HI-801, HI-501, or the flare gas recovery system. [OAC 252:100-8-6(a)(1)]

EUG 17 Gasoline Loading Rack Vapor Combustor Subject to NESHAP, Subpart CC: EU HI-13001; The Light Products Loading Terminal (LPLT).

EU	**Point**	**Description**
HI-13001	P69	Light Products Loading Terminal

Emission limits and standards for EU HI-13001:

	NO_X	**CO**	**VOC**
EU	**TPY**	**TPY**	**TPY**
HI-13001	15.8	39.5	73.66

a. The amount of gasoline and diesel loaded at the LPLT shall be recorded monthly and the 12-month rolling total shall be calculated monthly. [OAC 252:100-8-6(a)(3) & 100-43]

b. EU HI-13001 is subject to NSPS, Subpart J and shall comply with all applicable provisions including but not limited to: [40 CFR §§ 60.100-109]
   i. § 60.104 Standards for sulfur dioxide – (a)(1)
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii) or other alternative monitoring approved per § 60.13.
   iii. § 60.106 Test methods and procedures – (e)

c. EU HI-13001 shall comply with all applicable requirements including but not limited to the following requirements including but not limited to: [40 CFR Part 63]
   i. EU HI-13001 shall meet the design requirements of 40 CFR Part 63 NESHAP, Subpart A.

d. The LPLT is subject to NESHAP, 40 CFR Part 63, Subpart CC and shall comply with all applicable requirements including but not limited to: [40 CFR §§ 63.640-656]
   i. § 63.642 General Standards.
   ii. § 63.650 Gasoline Loading Rack Provisions.
   iii. § 63.655 Reporting and Recordkeeping Requirements.

e. Compliance with the emission limits shall be based on the following: the 12-month rolling total loading throughput of gasoline; and the following factors: VOC and CO: 10 mg/L loaded; NO_X: 4 mg/L loaded. Fugitive VOC emissions from the Light Products Loading Terminal shall be based on calculated loading losses and a 99.2% collection efficiency for gasoline. Compliance with the TPY limits shall be based on a 12-month rolling total and shall be calculated monthly. Performance test data may also be used to calculate these emissions. [OAC 252:100-8-6(a)(3) & 100-43]

EUG 18 FCCU Flue Gas Scrubber (FCCU No. 1 & 2 Regenerators and Boilers/CO Boilers B-253A & B-253B) Subject to NSPS, Subpart J, NESHAP Subpart UUU, & OAC 252:100-19 & 35: EU FGS-200.

EU	**Point**	**Description**
FGS-200	P70	FCCU Flue Gas Scrubber

Emission limits and standards for EU FGS-200:
[OAC 252:100-8-34(b) & Permit No. 98-172-C (M-20) PSD]
[Permit No. 98-172-TV (M-35)]

NO_X		**CO**		**PM_{10}[1]**		**SO_2**		**HCN**	
lb/hr[2]	**TPY[4]**	**lb/hr[2]**	**TPY[4]**	**lb/hr[2]**	**TPY[4]**	**lb/hr[2]**	**TPY[4]**	**lb/hr[3]**	**TPY[4]**
118.0	344.8	178.1	234.7	26.2	53.2	66.4	223.6	4.6	20.0

1 - The PM_{10} emission limits are based only on the front-half of the PM_{10} sampling train and were determined using USEPA Reference Method 5B.
2 - Three hour average.
3 - Daily average.
4 - 12-month rolling average.

SO_2 and NO_X emissions for EU FGS-200 shall not exceed the following limits:

[Permit No. 98-172-C (M-36)]

Additional Emission Limits	
SO_2 Emissions Limits	**Averaging Period**
50 ppmvd @ 0% O_2	7-day rolling average
25 ppmvd @ 0% O_2	365-day rolling average
NO_X (As NO_2) Emissions Limits	**Averaging Period**
160 ppmvd @ 0% O_2	7-day rolling average
80 ppmvd @ 0% O_2	365-day rolling average

a. EU FGS-200 shall be equipped with continuous emissions monitoring systems (CEMS) for determining and recording NO_X, CO, and SO_2 emissions corrected to dry basis and 0% O_2. The CEMS shall meet the applicable performance specifications of 40 CFR Part 60, Appendix B. [OAC 252:100-8-6(a)(3) & 100-43]

   i. With respect to the NO_X, SO_2, and O_2 CEMS, the source shall install, certify, calibrate, maintain and operate them in accordance with the provisions of 40 CFR §60.13 which are applicable only to CEMS (excluding those provisions applicable only to continuous opacity monitoring systems) and Part 60, Appendices A and F, and the applicable performance specification test of 40 CFR Part 60, Appendix B. With respect to 40 CFR Part 60 Appendix F, in lieu of the requirements of 40 CFR Part 60, Appendix F §§5.1.1, 5.1.3 and 5.1.4, the source must conduct either a RAA or a RATA on each CEMS at least once every three (3) years. The source must also conduct CGA each calendar quarter during which a RAA or a RATA is not performed.[Permit No. 2012-1523-C (M-7)]

b. The permittee shall compute the 12-month rolling total NO_X, CO, and SO_2 emissions from EU FGS-200 using the monthly average monitored NO_X, CO, and SO_2 concentrations along with the monthly average dry-basis stack gas flow rate.

[OAC 252:100-8-6(a)(3) & 100-43]

c. The off-gases from the FCCU No. 1 Regenerator shall be combusted in one of the CO Boilers prior to being processed by the FGS to reduce emissions of CO.

[OAC 252:100-8-34(b) & Permit No. 98-172-C (M-20) PSD]

d. The emissions of CO from the FCCU No. 1 Regenerator shall be reduced by use of complete secondary combustion of the waste gas generated. [OAC 252:100-35-2(b)]

   i. Emissions of CO from the FCCU No. 1 Regenerator shall be vented to and completely combusted in one of the CO Boilers.

e. The FCCU No. 2 Regenerator shall be operated in full combustion regeneration mode to reduce emissions of CO.

[OAC 252:100-8-34(b), Permit No. 98-172-C (M-20) PSD & 100-35-2(b)]

f. All off-gases from the FCCU No. 1 Regenerator/CO Boiler system and the FCCU No. 2 Regenerator shall be treated by a Wet Scrubber (WS) to control emissions of SO_2 from the FCCU. [OAC 252:100-8-34(b), Permit No. 98-172-C (M-20) PSD, & 100-19-12]

   i. The WS shall be designed and operated with devices that reduce the amount of entrained water in the WS off-gases.

g. The FCCU No. 1 Regenerator and the FCCU No. 2 Regenerator shall be operated with cyclones to reduce emissions of PM_{10}.

[OAC 252:100-8-34(b), Permit No. 98-172-C (M-20) PSD, & 100-19-12]

h. As provided under the alternative monitoring plan (AMP) for EUG FGS-200, as approved by EPA on April 28, 2016, in lieu of constructing and operating a Continuous Opacity Monitoring System, the permittee shall monitor the following key operating parameter limits (OPLs) to ensure that EUG FGS-200 functions as intended, and that emissions from the corresponding FCCU regenerator exhaust meet regulatory requirements. All OPLs are set on an hourly rolling average basis based on an evaluation of results from three one-hour test runs. [40 CFR §§ 60.13(i), 60.102, 60.105-108, 63.6(h)(9), 63.1564-1578, and OAC 252:100-8-6(a)(3) & 100-43]

  i. The minimum liquid-to-gas ratio (L/G), defined as total liquid flow rate (L) in gallons per minute (gpm) divided by total gas flow rate (G) in standard cubic feet per minute (scfm) shall be 0.050 gal/scf.
  ii. The minimum water pressure to the quench/spray tower nozzles shall be 39.9 pounds per square inch gauge pressure (psig).
  iii. The minimum pressure drop across the Agglo-filtering module (differential pressure or ΔP) shall be 1.1 inches water (in. H_2O).

i. EU FGS-200 is subject to NSPS, 40 CFR Part 60, Subpart J and shall comply with all applicable requirements including but not limited to: [40 CFR §§ 60.100-109]

  i. § 60.102 Standard for particulate matter.
    A. One (1) pound per 1,000 pounds of coke burned (front half only according to Method 5B or 5F, as appropriate), measured as a one-hour average over three performance test runs. [Permit No. 2012-1523-C (M-7)]
  ii. § 60.103 Standard for carbon monoxide.
    B. (500 ppmvd CO @ 0% O_2), measured as a one-hour block average.
    [Permit No. 2012-1523-C (M-7)]
  iii. § 60.104 Standard for sulfur oxides – (b-d).
  iv. § 60.105 Monitoring of emissions and operations – (a)(2), (a)(8-13), (c), (d), and (e)(2) or other alternative monitoring approved per § 60.13.
  v. § 60.106 Test Methods and Procedures (a-d) and (g-k).
  vi. § 60.107 Reporting and Recordkeeping Requirements (a-f).
  vii. § 60.108 Performance Test and Compliance Provisions (a-e).

j. EU FGS-200 is subject to NESHAP, Subpart UUU and shall comply with all applicable including but not limited to: [40 CFR §§ 63.1560-1579]

  ii. § 63.1560 What is the purpose of this subpart?
  iii. § 63.1561 Am I subject to this subpart?
  iv. § 63.1562 What parts of my plant are covered by this subpart?
  v. § 63.1563 When do I have to comply with this subpart?
  vi. § 63.1564 What are my requirements for metal HAP emissions from catalytic cracking units?
  vii. § 63.1565 What are my requirements for organic HAP emissions from catalytic cracking units?
  viii. § 63.1569 What are my requirements for HAP emissions from bypass lines?
  ix. § 63.1570 What are my general requirements for complying with this subpart?

x. § 63.1572 What are my monitoring installation, operation, and maintenance requirements?
xi. § 63.1574 What notifications must I submit and when?
xii. § 63.1575 What reports must I submit and when?
xiii. § 63.1576 What records must I keep, in what form, and for how long?
xiv. § 63.1577 What parts of the General Provisions apply to me?

k. The emission limits for EUG 18 are in effect upon startup of the FCCU until after shutdown of the FCCU. During all other times, while EUG 19 is in operation, the emission limits for EUG 19 are in effect. [Permit No. 98-172-C (M-36)]

l. The amount of nitrogen in the FCCU feedstock shall not exceed 3,350 ppmw. [Permit No. 98-172-C (M-20) PSD]

m. The permittee shall monitor and record the FCCU feedstock nitrogen content daily. When seven consecutive tests show that the nitrogen content of the FCCU feedstock is less than 80% of the FCCU feedstock nitrogen content limit, the frequency may be reduce to weekly testing. A weekly test may be conducted no sooner than 3 calendar days nor later than 7 calendar days after the most recent test. If the FCCU feedstock nitrogen content exceeds 80% of the FCCU feedstock nitrogen content limit, the testing shall revert to daily testing. [OAC 252:100-8-6(a)(3) & 100-43]

n. The permittee shall monitor and record the FCCU coke burn rate (daily average). [OAC 252:100-8-6(a)(3) & 100-43]

o. The permittee and shall calculate compliance with the HCN emission limit (daily) based on the average daily FCCU coke burn rate and the most recent FCCU feedstock nitrogen content. The HCN emissions shall be calculated using the most recent stack testing of the FCCU correlating the FCCU feedstock nitrogen content and FCCU coke burn rate to emissions of HCN. [OAC 252:100-8-6(a)(3) & 100-43]

EUG 19 Boilers/CO Boilers (B-253A & B-253B) Subject to NSPS, Subparts Db & J & OAC 252:100-19, 33, and 8-34: EU B-253A and B-253B. The CO Boilers are vented to EU FGS-200 and all emissions are associated with EU FGS-200.

EU	**Point**	**Description**	**MMBTUH**
B-253A	P70	CO Boiler	144.0
B-253B	P70	Boiler/CO Boiler	144.0

Emission limits and standards for the affected EU:

	NO_X		**CO**		**SO_2**	
EU	**lb/hr[1]**	**TPY[2]**	**lb/hr[1]**	**TPY[2]**	**lb/hr[1]**	**TPY[2]**
B-253A	8.64	37.84	11.86	51.94	4.84	21.19
B-253B	8.64	37.84	11.86	51.94	4.84	21.19

[1] - Three hour average.
[2] - 12-month rolling average.

a. The CO Boilers shall be vented to the FCCU WS. [OAC 252:100-8-34(b), Permit No. 98-172-C (M-20) PSD]

b. The B-253A shall be equipped with LNB.
[OAC 252:100-8-34(b) & Permit No. 98-172-C (M-20) PSD]

c. The B-253B shall be equipped with LNB.
[OAC 252:100-8-34(b) & Permit No. 98-172-C (M-20) PSD]

d. The off-gases from the FCCU No. 1 Regenerator shall be processed through EU B-253A and/or B-253B. [OAC 252:100-8-34(b) & Permit No. 98-172-C (M-20) PSD]

e. EU B-253A and B-253B are subject to NSPS, Subpart J and shall comply with all applicable requirements including but not limited to: [40 CFR §§ 60.100-109]
   i. § 60.104 Standards for sulfur dioxide – (a)(1)
   ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii)
   iii. § 60.106 Test methods and procedures – (e)

f. The owner or operator shall limit operation of EU B-253A and B-253B to an annual capacity factor (as defined in 40 CFR Part 60, Subpart Db) of 10 percent (0.10) or less for coal, oil, and natural gas. The owner or operator shall record and maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor individually for coal, oil, and natural gas. The annual capacity factor shall be determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month. The owner or operator shall demonstrate the maximum heat input capacity in accordance with § 60.46b(g). If this demonstration indicates that the maximum heat input capacity of the affected facility is less than that stated by the manufacturer of the affected facility, the maximum heat input capacity determined during this demonstration shall be used to determine the capacity utilization rate for the affected facility. Otherwise, the maximum heat input capacity provided by the manufacturer shall be used.
[OAC 252:100-8-6(a)(1), 100-8-6(a)(3), & 100-43]

g. EU B-253A and B-253B are subject to NSPS, Subpart Db and shall comply with all applicable provisions including but not limited to: [40 CFR §§ 60.40b-49b]
   i. § 60.49b Reporting and Recordkeeping Requirements – (a), (d), (o), (p), & (q).

h. Emissions of NO_X from the burners of EU B-253A shall not exceed 0.06 lb/MMBTU based on a 12-month rolling average.
[OAC 252:100-8-34(b) & Permit No. 98-172-C (M-20) PSD]

i. Emissions of NO_X from the burners of EU B-253B shall not exceed 0.06 lb/MMBTU based on a 12-month rolling average. [OAC 252:100-8-6(a)(1)]

j. EU B-253A and B-253B shall only combust natural gas, fuel gas as defined in § 60.101(d), or FCCU #1 regenerator flue gas or any combination thereof. [OAC 252:100-19-4]

k. The refinery shall use a flow meter to monitor fuel gas and air flow rates to the CO boiler(s), fuel gas Fd factors, as determined using fuel gas analyses, in conjunction with the FGS NO_X, SO_2, CO, and O_2 CEM(s) data to determine compliance with the above emission limits.
[OAC 252:100-8-6(a)(3) & 100-43]

l. The emission limits for EUG 18 are in effect upon startup of the FCCU until after shutdown of the FCCU. During all other times, while EUG 19 is in operation, the emission limits for EUG 19 are in effect. [Permit No. 98-172-C (M-36)]

EUG 20 Limited Use/Emergency Stationary Reciprocating Internal Combustion Engines (RICE) Subject to NSPS, Subpart IIII or JJJJ and/or NESHAP, Subpart ZZZZ: EU EEQ-8801, P-1806, P-1807A, P-1807B, P-1807C, EG-1880-01, EG1880-02, and EG-ADMIN.

EU	Point	Description	Make/Model	KW (HP)
EEQ-8801	P73	Wastewater Generator	Detroit DMT 825D-2	750 (1,006)
P-1806	P75	Fire Pond Water Pump	Cummins NT-855-F2	283 (380)
P-1807A	P76	HF Alky Emergency Deluge (East)	Caterpillar 3412 HRM	597 (800)
P-1807B	P77	HF Alky Emergency Deluge (Middle)	Caterpillar 3412 HRM	597 (800)
P-1807C	P78	HF Alky Emergency Deluge (West)	Caterpillar 3412 HRM	597 (800)
EG-1880-01	P79	Guard House Generator	Cummins WSG-1068	85.5 (115)
EG-1880-02	P80	Central Control Room Generator	Cummins QSTB-G5	100 (134)
EG-ADMIN	P91	New Admin Building Generator	Cummins QSX15-G9	400 (536)

Emission limits and standards for these EU:

a. EU EEQ-8801, P-1806, P-1807A, P-1807B, P-1807C, EG-1880-01, EG-1880-02, and EG-ADMIN are subject to NESHAP, 40 CFR Part 63, Subpart ZZZZ and shall comply with all applicable requirements. [40 CFR §§ 63.6580-6675]

<u>What This Subpart Covers</u>

i. § 63.6580 What is the purpose of subpart ZZZZ?
ii. § 63.6585 Am I subject to this subpart?
iii. § 63.6590 What parts of my plant does this subpart cover?
iv. § 63.6595 When do I have to comply with this subpart?

<u>Emission and Operating Limitations</u>

v. § 63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?
vi. § 63.6601 What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?
vii. § 63.6602 What emission limitations and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?
viii. § 63.6604 What fuel requirements must I meet if I own or operate a stationary CI RICE?

<u>General Compliance Requirements</u>

ix. § 63.6605 What are my general requirements for complying with this subpart?

Testing and Initial Compliance Requirements

x. § 63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

xi. § 63.6611 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or reconstructed 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?

xii. § 63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?

xiii. § 63.6615 When must I conduct subsequent performance tests?

xiv. § 63.6620 What performance tests and other procedures must I use?

xv. § 63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?

xvi. § 63.6630 How do I demonstrate initial compliance with the emission limitations, operating limitations, and other requirements?

Continuous Compliance Requirements

xvii. § 63.6635 How do I monitor and collect data to demonstrate continuous compliance?

xviii. § 63.6640 How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

Notifications, Reports, and Records

xix. § 63.6645 What notifications must I submit and when?

xx. § 63.6650 What reports must I submit and when?

xxi. § 63.6655 What records must I keep?

xxii. § 63.6660 In what form and how long must I keep my records?

Other Requirements and Information

xxiii. § 63.6665 What parts of the General Provisions apply to me?

xxiv. § 63.6670 Who implements and enforces this subpart?

xxv. § 63.6675 What definitions apply to this subpart?

b. EU EG-1880-02 and EG-ADMIN are subject to NSPS, 40 CFR Part 60, Subpart IIII and shall comply with all applicable requirements. [40 CFR §§ 60.4200-4219]

What This Subpart Covers

i. § 60.4200 Am I subject to this subpart?

Emission Standards for Owners and Operators

ii. § 60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

iii. § 60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

iv. § 60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Fuel Requirements for Owners and Operators

v. § 60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

Other Requirements for Owners and Operators

vi. § 60.4208 What is the deadline for importing or installing stationary CI ICE produced in previous model years?

vii. § 60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

Compliance Requirements

viii. § 60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

Testing Requirements for Owners and Operators

ix. § 60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?

x. § 60.4213 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?

Notification, Reports, and Records for Owners and Operators

xi. § 60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

General Provisions

xii. § 60.4218 What parts of the General Provisions apply to me?

xiii. § 60.4219 What definitions apply to this subpart?

c. EU EG1880-01 is subject to NSPS, 40 CFR Part 60, Subpart JJJJ and shall comply with all applicable requirements. [40 CFR §§ 60.4230-4248]

What This Subpart Covers

i. § 60.4230 Am I subject to this subpart?

Emission Standards for Owners and Operators

ii. § 60.4233 What emission standards must I meet if I am an owner or operator of a stationary SI internal combustion engine?

iii. § 60.4234 How long must I meet the emission standards if I am an owner or operator of a stationary SI internal combustion engine?

Other Requirements for Owners and Operators

iv. § 60.4235 What fuel requirements must I meet if I am an owner or operator of a stationary SI gasoline fired internal combustion engine subject to this subpart?

v. § 60.4236 What is the deadline for importing or installing stationary SI ICE produced in previous model years?

vi. § 60.4237 What are the monitoring requirements if I am an owner or operator of an emergency stationary SI internal combustion engine?

Compliance Requirements for Owners and Operators

vii. § 60.4243 What are my compliance requirements if I am an owner or operator of a stationary SI internal combustion engine?

Testing Requirements for Owners and Operators

viii. § 60.4244 What test methods and other procedures must I use if I am an owner or operator of a stationary SI internal combustion engine?

Notification, Reports, and Records for Owners and Operators

ix. § 60.4245 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary SI internal combustion engine?

General Provisions
x. § 60.4246 What parts of the General Provisions apply to me?
Definitions
xi. § 60.4248 What definitions apply to this subpart?

d. All of these EU shall be fitted with non-resettable hour-meters. [OAC 252:100-43]
e. The permittee shall record the number of hours each engine is operated each month and the reason for operation that month. [OAC 252:100-8-6(a)(3) & 100-43]
f. EU EEQ-8801, P-1806, P-1807A, P-1807B, P-1807C, EG-1880-02, and EG-ADMIN shall only be fired with diesel fuel. [OAC 252:100-19-4]
   i. The sulfur content of the diesel fuel for these EU shall not exceed 15 ppmw (on-road ultra low-sulfur diesel performance specification). [OAC 252:100-31-25(1)(B)]
g. EU EG-1880-01 shall only be fired with commercial natural gas.
[OAC 252:100-31-25(1)(A) & 19-4]
h. A serial number or another acceptable form of permanent (non-removable) identification shall be on each EU. [OAC 252:100-43]

EUG 21 Backup Flare Subject to NSPS, Subparts A & Ja and NESHAP, Subpart A: HI-81004.

EU	Point	Description
HI-81004	P81	Backup East Flare – 16” SASFF

a. EU HI-81004 is subject to NSPS, Subpart Ja and shall comply with all applicable provisions of NSPS, Subpart Ja including but not limited to:
[40 CFR §§ 60.100a-109a]
   i. § 60.102a Emissions limitations;
   ii. § 60.103a Work practice standards;
   iii. § 60.104a Performance tests;
   iv. § 60.107a Monitoring of emissions and operations for process heaters and other fuel gas combustion devices; and
   v. § 60.108a Recordkeeping and reporting requirements.
b. EU HI-81004 shall comply with all applicable requirements including but not limited to the following requirements: [40 CFR Parts 60 and 63]
   i. The flare shall meet the design requirements of 40 CFR Part 60 NSPS, Subpart A; or
   ii. The flare shall meet the design requirements of 40 CFR Part 63 NESHAP, Subpart A.

EUG 22 Instrument/Plant Air Compressor: EU C-80018.

EU	Point	Description	hp
C-80018	P82	Cummins N14 N14-C475	500

Emission limits and standards for EU C-80018:

	NO_X		CO	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**
C-80018	15.50	31.00	3.34	6.68

a. EU C-80018 shall not operate more than 4,000 hours in any 12-month period. [Permit No. 98-172-C (M-20) PSD]

b. EU C-80018 shall be fitted with a non-resettable hour-meter. [OAC 252:100-43]

c. The permittee shall record the number of hours the engine is operated each month. [OAC 252:100-8-6(a)(3) & 100-43]

d. EU C-80018 shall only be fired with diesel fuel [OAC 252:100-19-4]

e. The sulfur content of the diesel fuel shall not exceed 15 ppmw (on-road ultra low-sulfur diesel performance specification). [OAC 252:100-31-25(1)(B)]

f. Compliance with the emission limits shall be based on the hours of operation, the horsepower rating (hp), and the emissions factors from AP-42 (10/96), Section 3.3 or performance test data. Compliance with the TPY limits shall be based on a 12-month rolling total. [OAC 252:100-8-6(a)(3) & 100-43]

g. EU C-80018 shall be equipped with a permanent (non-removable) identification such as a serial number or another acceptable form of identification. [OAC 252:100-43]

h. Placement of EU C-80018 shall be limited to the north end of the FCCU area. [OAC 252:100-3]

EUG 23 SRU Molten Sulfur Storage & Loading Subject to OAC 252:100-31-26: EU MSLA-520, LR-SB001, SSP520, and SSPTTL. EU SSP520 is vented to the SRU incinerator or to the front end of the SRU and are incorporated into that limit as SO_2.

EU	Point	Description	# Arms
MSLA-520	P83	#1 SRU Railcar Molten Sulfur Loading Rack	1
LR-SB001	P84	#2 SRU Railcar Molten Sulfur Loading Rack	3
SSP-520	P85	#1 SRU Molten Sulfur Storage Pit	N/A
SSP-TTL	P86	#1 SRU Tank Truck Molten Sulfur Loading Arm	1

a. EU SSP-520 shall be vented to the SRU incinerator or the inlet of the SRU at all times. [OAC 252:100-31-26]

b. These EU are subject to OAC 252:100-31-26 and shall comply with all applicable provisions including but not limited to:

   i. These requirements shall not apply if a facility's emissions of H_2S do not exceed 0.3 lb/hr, two-hour average. [OAC 252:100-31-26(1)(A)]

   ii. Compliance with the 0.3 lb/hr limit shall be determined using the maximum actual loading rate and the H_2S concentration of the gases coming from the loading operation. The H_2S concentration shall be determined at least once monthly using stain tubes. [OAC 252:100-8-6(a)(3) & 100-43]

iii. If emissions are determined to be greater than 0.3 lb/hr, H_2S contained in the waste gas stream from any petroleum or natural gas process equipment shall be reduced by 95% by removal or by being oxidized to SO_2 prior to being emitted to the ambient air.

[OAC 252:100-31-26(1)(A)]

iv. The owner or operator shall install, maintain, and operate an alarm system that will signal a malfunction for all thermal devices used to control H_2S emissions from petroleum and natural gas processing facilities regulated under OAC 252:100-31-26(1). [OAC 252:100-31-26(1)(B)]

EUG 24 Continuous Catalyst Regeneration Vent (CCR) Subject to OAC 252:100-19 & 35 & NESHAP, Subpart UUU: EU CCR.

EU	Point	Description
CCR	P87	Platformer Catalyst Regeneration Combustion Vent

Emission limits and standards for EU CCR:

	NO_X		CO		PM_{10}	
EU	**lb/hr**	**TPY**	**lb/hr**	**TPY**	**lb/hr**	**TPY**
CCR	1.2	5.2	0.4	1.9	0.56	2.46

a. The CCR shall be operated in full combustion regeneration mode to reduce emissions of CO. Emissions of CO shall not exceed 0.44 lb/hr, three hour average.

[OAC 252:100-35-2(b)]

i. At least once per calendar quarter, the permittee shall conduct tests of CO emissions in the exhaust gases from the CCR when operating under representative conditions. CO Draeger Tubes or an equivalent method approved by AQD may be used for testing. Flow rates shall be based on process operating parameters at the time of the test. When four consecutive quarterly tests show compliance with the CO emission limit, the testing frequency may be reduced to semi-annual testing. A semi-annual test may be conducted no sooner than 60 calendar days nor later than 180 calendar days after the most recent test. Likewise, when the following two consecutive semi-annual tests show compliance, the testing frequency may be reduced to annual testing. An annual test may be conducted no sooner than 120 calendar days nor later than 365 calendar days after the most recent test. Upon any showing of non-compliance with emissions limitations, the testing frequency shall revert to quarterly.

[OAC 252:100-8-6(a)(3) & 100-43]

b. The sulfur content of the Platformer feed shall not exceed 5% by weight based on a 12-month rolling average. [OAC 252:100-8-6(a)(1)]

c. EU CCR is subject to NESHAP, Subpart UUU and shall comply with all applicable including but not limited to: [40 CFR §§ 60.1560-1579]

i. § 63.1560 What is the purpose of this subpart?
ii. § 63.1561 Am I subject to this subpart?
iii. § 63.1562 What parts of my plant are covered by this subpart?
iv. § 63.1563 When do I have to comply with this subpart?

v. § 63.1566 What are my requirements for organic HAP emissions from catalytic reforming units?
vi. § 63.1567 What are my requirements for inorganic HAP emissions from catalytic reforming units?
vii. § 63.1569 What are my requirements for HAP emissions from bypass lines?
viii. § 63.1570 What are my general requirements for complying with this subpart?
ix. § 63.1572 What are my monitoring installation, operation, and maintenance requirements?
x. § 63.1574 What notifications must I submit and when?
xi. § 63.1575 What reports must I submit and when?
xii. § 63.1576 What records must I keep, in what form, and for how long?
xiii. § 63.1577 What parts of the General Provisions apply to me?

d. Compliance with the emission limits shall be based on the maximum catalyst recirculation rate, a coke combustion rate of 7% of the catalyst processing rate, and the following emissions factors: AP-42 (1/95), Section 1.1, for sub-bituminous coal combustion: NO_X - 34 lb/ton of coke combusted (Pulverized coal fired, wet bottom); CO - 5 lb/ton of coke combusted (Spreader Stoker). Actual performance test and unit operating data may be substituted for the foregoing to demonstrate compliance. Compliance with the TPY limits shall be based on a 12-month rolling total and calculated monthly. Alternative methods to ensure compliance shall be approved by AQD prior to use.

[OAC 252:100-8-6(a)(3) & 100-43]

EUG 25 FCCU Catalyst Hopper Vent Subject to OAC 252:100-19: EU Cat_Hop.

EU	**Point**	**Description**
Cat_Hop	P88	FCCU Catalyst Hopper Vent

a. EU Cat_Hop shall be vented through a cyclone and then to the FCCU WS (FGS-200) or another equally effective control device.

[OAC 252:100-8-34(b) & Permit No. 98-172-C (M-20) PSD & OAC 252:100-19-12]

EUG 26 Wastewater Treatment Plant (WWTP) Bioreactors Atmospheric Vent (ATMV-8801), & Associated Control Device: Regenerative Thermal Oxidizer (RTO) (HI-8801). EU ATMV-8801 is subject to NESHAP (40 CFR Part 61), Subpart FF and NESHAP (40 CFR Part 63), Subpart CC. EU HI-8801 is subject to OAC 252:100-19, NSPS, Subpart J, and NESHAP (40 CFR Part 63), Subpart FF.

EU	**Point**	**Description**
ATMV-8801	P89	WWTP Bioreactors Off-Gas Atmospheric Vent
HI-8801	P90	WWTP Regenerative Thermal Oxidizer (15 MMBTUH)

Emission limits and standards for EU ATMV-8801 & HI-8801:

	NO_X	CO	SO_2	VOC
EU	**TPY**	**TPY**	**TPY**	**TPY**
ATMV-8801 HI-8801	26.7	5.5	16.3	33.0

a. The off-gases from the WWTP Bioreactors may be combusted by a properly operated and maintained RTO or vented to the atmosphere. [OAC 252:100-8-6(a)(1)]

b. EU HI-8801 and ATMV-8801 are subject to NESHAP, 40 CFR Part 61, Subpart FF and shall comply with all applicable provisions including but not limited to: [40 CFR §§ 61.340-359]

    i. § 61.342 Standards: General;
    ii. § 61.348 Standards: Treatment processes;
    iii. § 61.349 Standards: Closed-vent systems and control devices;
    iv. § 61.354 Monitoring of operations;
    v. § 61.355 Test methods, procedures, and compliance provisions;
    vi. § 61.356 Recordkeeping requirements; and
    vii. § 61.357 Reporting requirements.

c. When gases are being routed to EU ATMV-8801, the permittee shall monitor and record the outlet VOC concentration (using 40 CFR Part 60, Method 21) and flow of the waste gases exiting the WWTP Bioreactors initially within 24-hours of routing the gases from the WWTP Bioreactors to the atmospheric vent and subsequently every calendar day thereafter that gases are continued to be routed to the atmospheric vent. [OAC 252:100-8-6(a)(3) & 100-43]

d. EU HI-8801 is subject to NSPS, Subpart J and shall comply with all applicable provisions including but not limited to: [40 CFR §§ 60.100-109]

    i. § 60.104 Standards for sulfur dioxide – (a)(1);
    ii. § 60.105 Monitoring of operations – (a)(4), (e)(3)(ii); and
    iii. § 60.106 Test methods and procedures – (e).

e. When gases are being routed to EU HI-8801 for incineration, the permittee shall continuously monitor and record the temperature of the combustion zone of EU HI-8801 (three hour rolling average). [OAC 252:100-8-6(a)(3) & 100-43]

f. When gases are being routed to EU HI-8801 for incineration, the temperature of the combustion zone of EU HI-8801 shall not drop below 1,400 ºF based on a three hour rolling average. [OAC 252:100-8-6(a)(1)]

g. When gases are being routed to EU HI-8801 for incineration, the ammonia concentration of the waste gases vented to the WWTP RTO shall not exceed 315 ppmv. [OAC 252:100-8-6(a)(1)]

h. When gases are being routed to EU HI-8801 for incineration, the permittee shall monitor and record monthly the ammonia concentration and flow of the waste gases vented to the WWTP RTO. If three consecutive monthly tests are in compliance with the ammonia concentration limitation, the testing frequency may be reduced to quarterly testing. Upon any showing of non-compliance with the ammonia concentration limitation, the testing frequency shall revert to monthly testing. [OAC 252:100-8-6(a)(3) & 100-43]

i. Compliance with the emission limitations for EU ATMV-8801 and HI-8801 shall be based on a 12-month rolling total and the following: [OAC 252:100-8-6(a)(3) & 100-43]

i. ATMV-8801 - total monthly flow of gases exiting the WWTP Bioreactors and the monthly average VOC concentration.

ii. HI-8801 – total auxiliary fuel and waste gas flow rate (SCF), total auxiliary fuel and waste gas heat content (BTU/SCF), waste gas monthly average ammonia concentration (ppmv), and the following:

A. NO_X: auxiliary fuel - emission factor 0.12 lb/MMBTUH; waste gas - 95% combustion of NH_3 to NO_2.

B. CO: auxiliary fuel and waste gas - AP-42;

C. SO_2: auxiliary fuel and waste gas - H_2S concentration (ppmv) as measured for that time period and 100% combustion of H_2S to SO_2; and

D. VOC: auxiliary fuel - AP-42; waste gas - 95% combustion of average VOC concentration (ppmv).

j. Actual performance test and unit operating data may be substituted for the foregoing to demonstrate compliance. Compliance with the TPY limits shall be based on a 12-month rolling total and calculated monthly. Alternative methods to ensure compliance shall be approved by AQD prior to use. [OAC 252:100-8-6(a)(3) & 100-43]

EUG 27 Alkylate/Gasoline Railcar Loading Station Subject to NESHAP, Subpart CC: EU RCALOAD 900.

EU	**Point**	**Description**
RCALOAD 900	P81	Alkylate/Gasoline Railcar Loading Station

a. All emissions from the Alkylate/Gasoline Railcar Loading Station shall be vented through the Asphalt Blowstill Incinerator (HI-801) or the Wastwater Treatment Plant Regenerative Thermal Oxidizer (HI-8801). [Permit No. 98-172-C (M-20) PSD]

b. The amount of material loaded at the Alkylate/Gasoline Railcar Loading Station shall not exceed 15,000 gallons/hr based on a daily average or 733,505 bbl/year based on a 12-month rolling total, calculated monthly. The permittee shall record the type and amount of material loaded at the Alkylate/Gasoline Railcar Loading Station daily and monthly and calculate the 12-month rolling total, monthly.

[OAC 252:100-8-6(a)(1), 100-8-6(a)(3), & 100-43]

c. The Alkylate/Gasoline Railcar Loading Station is subject to NESHAP, 40 CFR Part 63, Subpart CC and shall comply with all applicable requirements including but not limited to:

[40 CFR §§ 63.640-656]

i. § 63.642 General Standards.

ii. § 63.650 Gasoline Loading Rack Provisions.

iii. § 63.655 Reporting and Recordkeeping Requirements.

EUG 28 Ethanol and Biodiesel Unloading Station: EU EtOHTT, EtOHRC, and BDTT. Emissions from ethanol and biodiesel unloading are insignificant. Recordkeeping is required to confirm this designation.

EU	Point	Description
EtOHTT	F20	Ethanol Tank Truck Unloading Station
EtOHRC	F21	Ethanol Railcar Unloading Station
BDTT	F22	Biodiesel Tank Truck Unloading Station

a. The permittee shall not unload more than 3,000,000 barrels of ethanol in any 12-month period. [OAC 252:100-8-6(a)(1)]
b. The permittee shall record the amount of ethanol unloaded monthly. [OAC 252:100-8-6(a)(3) & 100-43]
c. The permittee shall not unload more than 120,000 barrels of biodiesel in any 12-month period. [OAC 252:100-8-6(a)(1)]
d. The permittee shall record the amount of biodiesel unloaded monthly. [OAC 252:100-8-6(a)(3) & 100-43]

EUG 29 LPG Loading & Unloading Subject to OAC 252:100-37: EU LPG-RC-UNLOAD, LPG-TT-UNLOAD, LPG-RC-LOAD, and LPG-TT-LOAD.

EU	Point	Description
LPG-RC-UNLOAD	P92	Railcar LPG Unloading
LPG-TT-UNLOAD	P93	Tank Truck LPG Unloading
LPG-RC-LOAD	P94	Railcar LPG Loading
LPG-TT-LOAD	P95	Tank Truck LPG Loading

Emissions limits for LPG Loading & Unloading:

	VOC
Station (EU)	**TPY**
Railcar Loading (LPG)	45.9
Tank Truck Loading (LPG)	
Unloading (LPG)	

a. All loading and vapor lines shall be equipped with fittings that make vapor-tight connections and which must be closed when disconnected or which close automatically when disconnected. [OAC 252:100-37-16(a)(1)(A)(ii)]
b. The fittings used to connect to the tank truck or trailer shall be dry-disconnect couplings performing at a 2 cm^3 release per loading disconnect. [OAC 252:100-37-16(a)(2)]
c. The permittee shall record the amount of LPG loaded monthly. [OAC 252:100-8-6(a)(3) & 100-43]
d. Compliance with the emission limits shall be based on an emission factor of 3.74 lb VOC/disconnect except for loading of propane into tank trucks where a factor of 13.5 lb/disconnect shall be used. Compliance with the VOC emission limit shall be based on a

12-month rolling total and shall be calculated monthly. Alternative methods to ensure compliance may be approved by AQD. [OAC 252:100-8-6(a)(3) & 100-43]

EUG 30 Asphalt and No. 6 Fuel Oil Railcar and Tank Truck Loading: EU ASPHALT-RC-LOAD and ASPHALT-TT-LOAD.

EU	Point	Description	# Arms
ASPHALT-RC-LOAD	P96	Asphalt, No. 6 Fuel Oil, Slurry, Railcar Loading	5
ASPHALT-TT-LOAD	P97	Asphalt, No. 6 Fuel Oil, Slurry, Truck Loading	8

Emissions limits and standards for Asphalt and No. 6 Fuel Oil Railcar and Tank Truck Loading:

	VOC
EU	TPY
ASPHALT-RC-LOAD	16.69
ASPHALT-TT-LOAD	

a. The permittee shall record the amount of asphalt and No. 6 fuel oil loaded at these EU monthly. [OAC 252:100-8-6(a)(3) & 100-43]
b. The temperature of the asphalt loaded shall not equal or exceed 500 ºF. [OAC 252:100-8-6(a)(1)]
c. The temperature of the asphalt in the storage vessels from which the asphalt is being loaded shall be measured and recorded at least once a day during those days that asphalt is loaded from those storage vessels. [OAC 252:100-8-6(a)(3) & 100-43]
d. Compliance with the emission limits shall be based on AP-42 (1/95), Section 5.2 and the actual throughputs or using other methods approved by the AQD. Compliance with the VOC emissions limit shall be based on a 12-month rolling total and shall be calculated monthly. Alternative methods to ensure compliance may be approved by AQD. [OAC 252:100-8-6(a)(3) & 100-43]

EUG 31 Fugitive Equipment Leaks Subject to LDAR Programs NSPS, Subpart GGG & NESHAP, Subpart CC.[1] Fugitive equipment items do not have specific limitations, except to comply with the applicable LDAR programs.

EU	Point	Description
LDAR 100	F23	Area 100: Crude Unit, Crude Unit MEROX, Asphalt Blowstill Unit, and Vent Gas Recovery & Compressors
LDAR 200	F27	Area 200 - Unsat Gas Unit
LDAR 250	F28	Area 250 - Olefin Unit
LDAR 400	F29	Area 400 - NHT & Reforming Unit
LDAR 520	F30	Area 520 - SCOT, TGTU & ARU
LDAR 550	F31	Area 550 - Fuel Gas Amine Unit
LDAR 570	F32	Area 570 - #2 TGTU

EU	Point	Description
LDAR 600	F33	Area 600 – DHDS Unit
LDAR 650	F34	Area 650 – CFHT Unit
LDAR 670	F35	Area 670 – Hydrocracker/Co-Processor Unit
LDAR 700	F36	Area 700 & 720 – Plant MEROX Unit
LDAR 800	F37	Area 800 – Plant Utilities System & Caustic Unit
LDAR 810	F38	Area 810 – East & West Flare System
LDAR 880	F39	Area 880 – WWTP
LDAR 900	F40	Area 900 – Alkylation Unit
LDAR 950	F41	Area 950 – C3/C4 Splitter Unit
LDAR 2100	F42	Area 2100 – PMA Unit
LDAR LPLT	F43	Light Product Loading Terminal
LDAR Rail LPGU	F44	Railcar LPG Unloading Station
LDAR Truck LPGU	F45	Tank Truck LPG Unloading Station
LDAR Rail LPGL	F46	Railcar LPG Loading Station
LDAR Truck LPGL	F47	Tank Truck LPG Loading Station
LDAR Rail Asphalt	F48	Railcar Asphalt Loading Station
LDAR Truck Asphalt	F49	Asphalt Tank Truck Loading Station
LDAR Truck Crude	F50	Tank Truck Crude Oil Unloading Station
LDAR Alkylate	F51	VOC Railcar Loading Station
LDAR Tank farm	F52	Tank Farm Area
LDAR Biodiesel	F53	Biodiesel Unloading & Transfer

[1] - LDAR 300, LDAR 450, and LDAR Biodiesel are subject to NSPS, Subpart GGGa and NESHAP, Subpart CC. All other EU are subject to NSPS, Subpart GGG and NESHAP, Subpart CC.

a. All affected equipment, in HAP service (contacting >5% by weight HAP), shall comply with NESHAP, 40 CFR Part 63, Subpart CC. The permittee shall comply with the applicable sections for each affected component including but not limited to:

[40 CFR §§ 63.640-656]

i. § 63.642 General Standards – (c), (d)(1), (e), & (f);
ii. § 63.648 Equipment Leak Standards – (a), (b), (c), & (e-i);
iii. § 63.655 Reporting and Recordkeeping Requirements – (d), & (f-h).

b. Equipment determined not to be in HAP service (contacting <5% by weight HAP), which was constructed, reconstructed, or modified after January 4, 1983, and on or before November 7, 2007, and is in VOC service (contacting >10% by weight VOC) shall comply with the requirements of NSPS 40 CFR Part 60, Subpart GGG including but not limited to:

[40 CFR §§ 60.590-593]

i. § 60.592 Standards (a-e);
ii. § 60.593 Exceptions (a-e).

EUG 32 Fugitive Equipment Leaks Subject to LDAR Programs NSPS, Subpart GGGa. Fugitive equipment items do not have specific limitations, except to comply with the applicable LDAR programs.

EU	Point	Description
LDAR 260	F100	Area 260 - Gasoline Desulfurization Unit
LDAR 300	F54	Area 300 - Sat Gas Unit
LDAR 450	F55	Area 450 - BenSat Unit

a. All equipment in VOC service (contacting >10% by weight VOC) shall comply with the requirements of NSPS 40 CFR Part 60, Subpart GGGa including but not limited to: [40 CFR §§ 60.590a-593a]
   i. § 60.592a Standards (a-e);
   ii. § 60.593a Exceptions (a-e).

EUG 33 Fugitive Equipment Leaks Subject to LDAR Programs NSPS, Subpart GGG. Fugitive equipment items do not have specific limitations, except to comply with the applicable LDAR programs.

EU	Point	Description
LDAR 150	F56	Area 150 – Hydrogen Unit
LDAR 500	F57	Area 500 - #1 SRU
LDAR 560	F58	Area 560 - #2 SRU
LDAR 580	F59	Area 580 - #2 ARU
LDAR 820	F60	Area 820 - #1 SWS
LDAR 860	F61	Area 860 – Instrument Air System

a. Equipment which was constructed, reconstructed, or modified after January 4, 1983, and on or before November 7, 2007, and is in VOC service (contacting >10% by weight VOC) shall comply with the requirements of NSPS 40 CFR Part 60, Subpart GGG including but not limited to: [40 CFR §§ 60.590-593]
   i. § 60.592 Standards (a-e);
   ii. § 60.593 Exceptions (a-e).

EUG 34 Fugitive Equipment Leaks Subject to LDAR Programs NSPS, Subpart GGG & GGGa. Fugitive equipment items do not have specific limitations, except to comply with the applicable LDAR programs.

EU	Point	Description
LDAR 830	F62	Area 830 - #2 SWS

a. Equipment which was constructed, reconstructed, or modified after November 7, 2007, and which is in VOC service (contacting >10% by weight VOC) shall comply with the requirements of NSPS 40 CFR Part 60, Subpart GGGa including but not limited to:

[40 CFR §§ 60.590a-593a]

i. § 60.592a Standards (a-e);
ii. § 60.593a Exceptions (a-e).

EUG 35 Wastewater Plant QQQ Fugitive Sources Subject to NESHAP, Subpart CC, LDAR Program. Fugitive equipment items do not have specific limitations, except to comply with the applicable LDAR programs.

EU	Point	Description
QQQ 100 (1 of 4)	F63	Area 100 (1 of 4) – Crude Unit
QQQ 100 (2 of 4)	F64	Area 100 (2 of 4) – Crude Unit MEROX
QQQ 100 (3 of 4)	F65	Area 100 (3 of 4) – Asphalt Blowstill Unit
QQQ 100 (4 of 4)	F66	Area 100 (4 of 4) – Vent Gas Recovery & Compressors
QQQ 150	F67	Area 150 – Hydrogen Unit
QQQ 200	F68	Area 200 – Unsat Gas Unit
QQQ 250	F69	Area 250 – Olefin Unit
QQQ 300	F70	Area 300 – Sat Gas Unit
QQQ 400	F71	Area 400 – NHT & Reforming Unit
QQQ 450	F72	Area 450 – BenSat Unit
QQQ 500	F73	Area 500 - #1 SRU
QQQ 520	F74	Area 520 – SCOT, TGTU & ARU
QQQ 550	F75	Area 550 – Fuel Gas Amine Unit
QQQ 560	F76	Area 560 - #2 SRU
QQQ 570	F77	Area 570 - #2 TGTU
QQQ 580	F78	Area 580 - #1 ARU
QQQ 600	F79	Area 600 – DHDS Unit
QQQ 650	F80	Area 650 – CFHT Unit
QQQ 670	F81	Area 670 – Hydrocracker/Co-Processor Unit
QQQ 700	F82	Area 700 & 720 – Plant MEROX Unit
QQQ 800	F83	Area 800 – Plant Utilities System & Caustic Unit
QQQ 810	F84	Area 810 – East & West Flare System
QQQ 820	F85	Area 820 - #1 SWS
QQQ 830	F86	Area 830 - #2 SWS
QQQ 880 (1 of 2)	F87	Area 880 – WWTP

EU	Point	Description
QQQ 880 (2 of 2)	F88	Area 880 – ILS
QQQ 900	F89	Area 900 – Alkylation Unit
QQQ 950	F90	Area 950 – C3/C4 Splitter Unit
QQQ 2100	F91	Area 2100 – PMA Unit
QQQ LPLT	F92	Light Product Loading Terminal
QQQ Tank Farm	F93	Tank Farm
QQQ STG	F94	FCCU Steam Turbine Generators
QQQ WGS	F95	FCCU Flue Gas Scrubber
QQQ WHSE	F96	WHSE Yard
QQQ Bundle Pads	F97	Bundle Pads

a. All affected equipment shall comply with NSPS, 40 CFR Part 63, Subpart CC. The permittee shall comply with the applicable sections for each affected component including but not limited to: [40 CFR §§ 63.640-656]
   i. § 63.642 General Standards
   ii. § 63.647 Wastewater Provisions
   iii. § 63.655 Reporting and Recordkeeping Requirements

EUG 36 Miscellaneous Process Vents (MPV) Subject to NESHAP, Subpart CC. These MPV do not have specific limitations, except to comply with the applicable requirements of the NESHAP.

EU	Point	MPV Vented to Flares or Other Control Devices
G1 MPV LCV813027	P98	East Flare KO Drum
G1 MPV LCV813029	P99	West Flare KO Drum
G1 MPV PCV5417	P100	Alky Acid Gas KOH Scrubber (T-901) KO Drum
G1 MPV PCV154013	P101	Hydrogen Unit (V-1501 through V-1510) PSA Off-gas Pressure Control
G1 MPV BV9A(I)	P102	CCR Lock Hopper No. 1 (V-418) Purge Control (II)
G1 MPV BV49A(I)	P103	CCR Lock Hopper No. 2 (V-424) Purge Control (II)
G1 MPV BV44(I)	P104	CCR Vent Drum No. 1 (V-428) Purge Control (II)
G1 MPV BV44(II)	P105	CCR Vent Drum No. 2 (V-429) Purge Control
G1 MPV BV4	P106	CCR Vent Drum No. 3 (V-432) Purge Control
G1 MPV BV15	P107	CCR Vent Drum No. 4 (V-433) Purge Control
G1 MPV FI32552	P108	MEROX De-Sulfide Settler (V-732) Purge Control
G1 MPV BV9A(II)	P109	Reformer Recycle Gas Coalescer (Z-402) Purge Control (II)
G1 MPV BV49A(II)	P110	Reformer Booster Gas Coalescer (Z-404) Purge Control (II)

a. All affected equipment shall comply with NESHAP, 40 CFR Part 63, Subpart CC. The permittee shall comply with the applicable sections for each affected component including but not limited to: [40 CFR §§ 63.640-656]

i. § 63.642 General Standards - (c-g), (i), (k), & (l);
ii. § 63.643 Miscellaneous process vent provisions - (a & b);
iii. § 63.644 Monitoring provisions for miscellaneous process vents - (a - e);
iv. § 63.645 Test methods and procedures for miscellaneous process vents - (a-h);
v. § 63.652 Emissions averaging provisions.
vi. § 63.653 Monitoring, recordkeeping, and implementation plan for emissions averaging.
vii. § 63.655 Reporting and Recordkeeping Requirements - (e-i).

EUG 37 Sources Vented to the Fuel Gas Recovery System (FGRS). These sources are not MPV because they are routed to the FGRS.

EU	Point	Sources Vented to FGRS
G1 MPV HV2527	P111	FCCU Debutanizer (T-205) Pressure Control
G1 MPV PCV824030B	P112	#1 SWS (T-82001) Pressure Control
G1 MPV PCV834051B	P113	#2 SWS (T-83001) Pressure Control
G1 MPV HV9507	P114	Alky Isostripper Receiver (V-903) Pressure Control Through KOH Scrubber (T-901)
G1 MPV PSE94139	P115	Alky CBM Surge Drum (V-923) Pressure Control Through KOH Scrubber (T-901)
G1 MPV HV9501	P116	Alky Depropanizer (V-905) Pressure Control Through KOH Scrubber (T-901)
G1 MPV PCV14071	P117	Crude Unit Fractionator Overhead Receiver (V-120) Pressure Control
G1 MPV PCV154007	P118	Hydrogen Unit Cold Separator (V-15003) Pressure Control
G1 MPV PCV154009	P119	Hydrogen Unit (V-1501 through V-1510) Hydrogen Offgas Pressure Control
G1 MPV PCV2401B	P120	FCCU Feed Surge Drum (V-201) Pressure Control
G1 MPV PV2436	P121	FCCU Fractionator Overhead Receiver (V-203) Pressure Control
G1 MPV PCV3502	P122	Sat Gas DIB Fractionator Overhead Receiver (V-304) Pressure Control
G1 MPV PCV3411B(I)	P123	Sat Gas Debutanizer Feed Surge Drum (V-305) Pressure Control
G1 MPV BV9(I)	P124	CCR Lock Hopper No. 1 (V-418) Purge Control (I)
G1 MPV BV49(I)	P125	CCR Lock Hopper No. 2 (V-424) Purge Control (I)
G1 MPV BV49(II)	P126	CCR Vent Drum No. 1 (V-428) Purge Control (I)
G1 MPV PCV4438B (I)	P127	NHT Feed Surge Drum (V-439) Pressure Control
G1 MPV PCV5302	P128	#1 SRU Amine Regenerator Overhead Receiver (V-501) Pressure Control
G1 MPV PCV58448	P129	#2 SRU Amine Regenerator Overhead Receiver (V-5802) Pressure Control
G1 MPV PCV6418A	P130	DHDS Feed Surge Drum (V-608) Pressure Control
G1 MPV PCV64235	P131	DHDS Fractionator Overhead Receiver (V-623) Pressure Control

EU	Point	Sources Vented to FGRS
G1 MPV PCV64505	P132	CFHT Fractionator Overhead receiver (V-6511) Pressure Control
G1 MPV PCV6514165	P133	CFHT recycle Gas Cyclone Separator (V-6514) Pressure Control (I)
G1 MPV PCV6514166	P134	CFHT recycle Gas Cyclone Separator (V-6514) Pressure Control (II)
G1 MPV PCV8415B	P135	General Refinery Fuel Gas Drum (V-804) Pressure Control
G1 MPV BV9(II)	P136	Reformer Recycle Gas Coalescer (Z-402) Purge Control (I)
G1 MPV BV49(III)	P137	Reformer Booster Gas Coalescer (Z-404) Purge Control (I)
G1 MPV PCV654585	P138	CFHT Flare Header Fuel Gas Purge Control (I)
G1 MPV PCV654586	P139	CFHT Flare Header Fuel Gas Purge Control (II)
G1 MPV PCV674060	P140	Hydrocracker Flare Header Fuel Gas Purge Control
G1 MPV PCV64719	P141	DHDS High Pressure Drain Drum (V-627) Pressure Control
G1 MPV PCV56463	P142	#2 SRU Hot Oil Heater Surge Drum (V-5604) Fuel Gas Purge Control
G1 MPV PCV2458	P143	FCCU Flare Header Fuel Gas Purge Control
G1 MPV FI58221	P144	#2 ARU Flare Header Fuel Gas Purge Control
G1 MPV FI56209	P145	#2 SRU Flare Header Fuel Gas Purge Control
G1 MPV 3451B(II)	P146	Sat Gas Debutanizer Overhead Receiver (V-301) Pressure Control
G1MPV FE102014	P147	Vacuum Tower Hotwell (V-105)
G1MPV FE102021	P148	Vent Gas Recovery Compressor Discharge Drum (V-10124)
G1MPV V10123	P149	Hotwell Compressor Discharge Drum (V-10123)
G1MPV PCV2451	P150	FCCU Sponge Gas Absorber (T-204)
G1MPV PCV2452B	P151	FCCU Deethanizer Overhead Receiver (V-207)
G1MPV PCV3451	P152	Sat Gas Debutanizer Overhead Receiver (V-301)
G1MPV PCV3408	P153	Sat Gas Deethanizer Overhead Receiver (V-302)
G1MPV PV73	P154	NHT Stripper Overhead Receiver (V-402)
G1MPV PV36A	P155	NHT Stripper Cold Separator (V-436)
G1MPV PV6422	P156	DHDS Low Pressure Receiver (V-602)
G1MPV PV6463	P157	DHDS Stripper Overhead Receiver (V-622)
G1MPV FV652170	P158	CFHT Recycle Gas Amine Contactor Purge (T-6501)
G1MPV PV654410	P159	CFHT Cold Flash Drum (V-6510)
G1MPV PV654490	P160	CFHT Offgas After Cooler Receiver (V-6522)
G1MPV FE832016	P161	#2 SWS Overhead Receiver (V-83001)
G1MPV FE822019	P162	#1 SWS Overhead Receiver (V-82001)
G1MPV PV4434B (II)	P163	NHT Feed Surge Drum (V-439)
G1MPV PV64235	P164	DHDS Fractionator Overhead Receiver (V-623)
G1MPV PV3411A	P165	Sat Gas Debutanizer Feed Surge Drum (V-305)
G1MPV PCV55423	P166	MDEA Rich Amine Flash Drum (V-55005)
G1MPV PV245	P167	Reformer Debutanizer Overhead Receiver (V-408)

EU	Point	Sources Vented to FGRS
G1MPV PV1608	P168	Reformer Net Gas Absorber Overhead (T-404)
G1MPV PV45448	P169	ISOM Net Gas Caustic Scrubber Overhead (T-452)
G1MPV PV55401	P170	Amine Unit Offgas Scrubber Overhead (V-553)
G1MPV PCV154009	P171	PSA Excess Hydrogen (V-1501 through V-1510)
G1MPV PCV9477	P172	PSA Excess Hydrogen (V-1501 through V-1510)
G1MPV PV9447	P173	Propane Scrubber Overhead (V-909 & V-910)
G1MPV PV904321	P174	Dehydrator Feed Surge Drum (V-924)
G1MPV PCV8412	P175	Reformer Fuel Gas Drum (V-412)
G1MPV PV14708	P176	Hotwell Compressor Separator (V-10123)
G1MPV PCV152012	P177	PSA Offgas (V-1501 through V-1510)
G1MPV PV604121	P178	DHDS Stripper Overhead Receiver Vent #2
G1 MPV PM199-B1A1	P179	Bensat Closed Collection Drain Drum (V-4507) Continuous Flare Pressure Control Valve
G1 MPV P45115-A1A1	P180	Bensat Flare Header Continuous Purge Gas Valve
G1 MPV PV-45441	P181	BenSat Overhead Receiver (V-452) Pressure Control Valve
G1 MPV PCV BSP2	P182	Makeup Hydrogen Compressor Discharge Drum
G1 MPV PCV BSP5	P183	Stabilizer Reboiler Pressure Control
G1 MPV PCV BSP6	P184	Splitter Reboiler Pressure Control

a. All affected equipment shall be routed to a fuel gas system. [OAC 252:100-8-6(a)(1)]

i. *Fuel gas system* means the offsite and onsite piping and control system that gathers gaseous streams generated by refinery operations, may blend them with sources of gas, if available, and transports the blended gaseous fuel at suitable pressures for use as fuel in heaters, furnaces, boilers, incinerators, gas turbines, and other combustion devices located within or outside of the refinery. The fuel is piped directly to each individual combustion device, and the system typically operates at pressures over atmospheric. The gaseous streams can contain a mixture of methane, light hydrocarbons, hydrogen and other miscellaneous species. [40 CFR §§ 63.641]

ii. No testing, monitoring, recordkeeping, or reporting is required under 40 CFR Part 63, Subpart CC for refinery fuel gas systems or emission points routed to refinery fuel gas systems. [40 CFR §§ 63.640(d)(5)]

iii. Additional sources may be vented to the fuel gas system at any time. [OAC 252:100-8-6(a)(1)]

EUG 38 Group 2 Miscellaneous Process Vents (MPV) Subject to NESHAP, Subpart CC. These MPV do not have specific limitations, except to comply with the applicable requirements of the NESHAP.

EU	Point	Sources Vented to FGRS
GII MPV V150004	P185	Hydrogen Unit Deaerator Vent (V-150004)

a. All affected equipment shall comply with NESHAP, 40 CFR Part 63, Subpart CC. The permittee shall comply with the applicable sections for each affected component including but not limited to: [40 CFR §§ 63.640-656]
   i. § 63.642 General Standards - (c-g), (i), (k), & (l);
   ii. § 63.643 Miscellaneous process vent provisions - (a & b);
   iii. § 63.644 Monitoring provisions for miscellaneous process vents - (a - e);
   iv. § 63.645 Test methods and procedures for miscellaneous process vents - (a-h);
   v. § 63.652 Emissions averaging provisions.
   vi. § 63.653 Monitoring, recordkeeping, and implementation plan for emissions averaging.
   vii. § 63.655 Reporting and Recordkeeping Requirements - (e-i).

EUG 39 Group 2 Miscellaneous Process Vents (MPV) Subject to NESHAP, Subpart LLLLL. This MPV does not have specific limitations, except to comply with the applicable requirements of the NESHAP.

EU	Point	Description
PMA SCRUB VENT	P186	PMA Unit Storage Tanks Nitrogen Blanket Scrubber
ASV Mist Eliminator	P226	Asphalt Storage Tanks Mist Eliminator

a. The permittee shall comply with NESHAP, 40 CFR Part 63, Subpart LLLLL for the affected storage vessels including but not limited to: [40 CFR §§ 63.8680-8698]
   i. § 63.8680 What is the purpose of this subpart?
   ii. § 63.8681 Am I subject to this subpart? (a-f)
   iii. § 63.8682 What parts of my plant does this subpart cover? (a-e)
   iv. § 63.8683 When must I comply with this subpart? (b & d)
   v. § 63.8684 What emission limitations must I meet? (a)
   vi. § 63.8685 What are my general requirements for complying with this subpart? (a-d)
   vii. § 63.8686 By what date must I conduct performance tests or other initial compliance demonstrations? (a & b)
   viii. § 63.8687 What performance tests, design evaluations, and other procedures must I use? (a-e)
   ix. § 63.8688 What are my monitoring installation, operation, and maintenance requirements?
   x. § 63.8689 How do I demonstrate initial compliance with the emission limitations? (a-c)
   xi. § 63.8692 What notifications must I submit and when? (a-f)
   xii. § 63.8693 What reports must I submit and when? (a-f)
   xiii. § 63.8694 What records must I keep? (a & b)
   xiv. § 63.8695 In what form and how long must I keep my records? (a-c)
   xv. § 63.8696 What parts of the General Provisions apply to me?

EUG 40 Stationary Reciprocating Internal Combustion Engines (RICE) Subject to NSPS, Subpart IIII and/or NESHAP, Subpart ZZZZ: EU P850A, P850B, P850C, P850D, P850E, and FWPE-1.

EU	Point	Make/Model	KW (HP)	Applicable Subparts
P850A	P187	Deutz F4914	61.5 (82.5)	IIII, ZZZZ
P850B	P188	Deutz F4912	54 (72.5)	ZZZZ
P850C	P189	John Deere 4045DF 270B	60 (80)	ZZZZ
P850D	P190	John Deere 4045TF 280B	63 (84)	IIII, ZZZZ
P850E	P191	John Deere 4045TF 275B	86 (115)	ZZZZ
FWPE-1	P226	Caterpillar 3406C	345 (460)	ZZZZ

Emission limits and standards for these EU:

a. EU P850A, P850B, P850C, P850D, P850E, and FWPE-1 are subject to NESHAP, 40 CFR Part 63, Subpart ZZZZ and shall comply with all applicable requirements, including but not limited to: [40 CFR §§ 63.6580-6675]

<u>What This Subpart Covers</u>

i. § 63.6580 What is the purpose of subpart ZZZZ?
ii. § 63.6585 Am I subject to this subpart?
iii. § 63.6590 What parts of my plant does this subpart cover?
iv. § 63.6595 When do I have to comply with this subpart?

<u>Emission and Operating Limitations</u>

v. § 63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?
vi. § 63.6601 What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?
vii. § 63.6602 What emission limitations and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?
viii. § 63.6604 What fuel requirements must I meet if I own or operate a stationary CI RICE?

<u>General Compliance Requirements</u>

ix. § 63.6605 What are my general requirements for complying with this subpart?

<u>Testing and Initial Compliance Requirements</u>

x. §63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?
xi. § 63.6611 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or reconstructed 4SLB SI

stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?

xii. § 63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?

xiii. § 63.6615 When must I conduct subsequent performance tests?

xiv. § 63.6620 What performance tests and other procedures must I use?

xv. § 63.6625 What are my monitoring, installation, operation, and maintenance requirements?

xvi. § 63.6630 How do I demonstrate initial compliance with the emission limitations, operating limitations, and other requirements?

<u>Continuous Compliance Requirements</u>

xvii. § 63.6635 How do I monitor and collect data to demonstrate continuous compliance?

xviii. § 63.6640 How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

<u>Notifications, Reports, and Records</u>

xix. § 63.6645 What notifications must I submit and when?

xx. § 63.6650 What reports must I submit and when?

xxi. § 63.6655 What records must I keep?

xxii. § 63.6660 In what form and how long must I keep my records?

<u>Other Requirements and Information</u>

xxiii. § 63.6665 What parts of the General Provisions apply to me?

xxiv. § 63.6670 Who implements and enforces this subpart?

xxv. § 63.6675 What definitions apply to this subpart?

b. EU P850A and P850D are subject to NSPS, 40 CFR Part 60, Subpart IIII and shall comply with all applicable requirements. [40 CFR §§ 60.4200-4219]

<u>What This Subpart Covers</u>

i. § 60.4200 Am I subject to this subpart?

<u>Emission Standards for Owners and Operators</u>

ii. § 60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

iii. § 60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

iv. § 60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

<u>Fuel Requirements for Owners and Operators</u>

v. § 60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

<u>Other Requirements for Owners and Operators</u>

vi. § 60.4208 What is the deadline for importing or installing stationary CI ICE produced in previous model years?

vii. § 60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

viii. Compliance Requirements

ix. § 60.4210 What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?

x. § 60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

<u>Testing Requirements for Owners and Operators</u>

xi. § 60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?

xii. § 60.4213 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?

<u>Notification, Reports, and Records for Owners and Operators</u>

xiii. § 60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

<u>General Provisions</u>

xiv. § 60.4218 What parts of the General Provisions apply to me?

xv. § 60.4219 What definitions apply to this subpart?

c. EU P850A, P850B, P850C, P850D, P850E, FWPE-1 shall only be fired with diesel fuel. [OAC 252:100-19-4]

d. The sulfur content of the diesel fuel for these EU shall not exceed 15 ppmw (non-road ultra low-sulfur diesel performance specification). [OAC 252:100-31-25(1)(B)]

e. Engine FWPE-1 shall be equipped with a non-resettable hour meter. Engine FWPE-1 shall be limited to no more than 1,200 hours of operation in any 12-month period. For engine FWPE-1, the permittee shall record the hours of operation monthly and calculate 12-month rolling totals.

f. A serial number or another acceptable form of permanent (non-removable) identification shall be on each EU. [OAC 252:100-43]

EUG 41 Startup, Shutdown, and Maintenance (SSM) Activities

The nature of refining operations requires certain activities that are outside normal continuous operations. These activities result in air emissions that exceed the emission rate of normal operations.

EU	Point	Activity
FGS-200	P70	FCCU Startup
FGS-200	P70	FCCU Shutdown
HI-81001	P63	West Flare, CFHT & Hydrocracker Shutdown
HI-81003	P65	East Flare, C-114 Shutdown
HI-81001 & HI-81003	P63 & P65	West & East Flares, Misc. Refinery Unit Start Up/Shut Down
RTDFUG	Fugitive	Refinery Turnaround Depressurization (Fugitive)
TDCSMFUG	Fugitive	Tank Degassing, Changes in Service, Maintenance

Startup, Shutdown, and Maintenance (SSM) Emissions (Tons) per Event

Event (Release Point)	**CO**	**NO_X**	**SO_2**	**PM_{10}**	**VOC**	**H_2S**	**HF**
FCCU Startup (P70)	1.90	NA	NA	NA	NA	NA	NA
FCCU Shutdown (P70)	1.40	0.40	NA	NA	NA	NA	NA
CFHT & Hydrocracker Shutdown (P63)	0.50	0.08	0.25	NA	NA	NA	NA
C-114 Shutdown (P65)	0.50	0.08	0.25	NA	NA	NA	NA
Misc. Refinery Unit Start Up (P63 & P65)	0.40	0.06	0.25	0.10	0.12	NA	NA
Misc. Refinery Unit Shut Down (P63 & P65)	0.40	0.06	0.25	0.10	0.12	NA	NA
Refinery Turnaround Depressurization (Fugitive)	NA	NA	NA	NA	36.0	0.10	0.05
Tank degassing, changes in service, maintenance	NA	NA	NA	NA	2.00	0.03	NA

* These emissions do not include insignificant or trivial activities.

EUG 42A CFHT Induced Draft Cooling Tower, 900-hp, 310 MMBTUH, 20,000 GPM, Heat Exchangers W/HAP Concentration >5%, W/Pressure > Cooling Water Pressure, & Subject to NESHAP, Subpart CC. These heat exchangers do not have specific limitations, except to comply with the applicable requirements of the NESHAP.

EU	**Point**	**Heat Exchangers**
C-150001	P192	E-607A – DHDS Stripper Overhead Light Naphtha Condenser
		E-607B – DHDS Stripper Overhead Light Naphtha Condenser
		E-60034 – DHDS Fractionator Heavy Naphtha Product Cooler
		E-205A – FCCU Fractionator Overhead Light Naphtha Condenser
		E-205B – FCCU Fractionator Overhead Light Naphtha Condenser
		E-205C – FCCU Fractionator Overhead Light Naphtha Condenser
		E-205D – FCCU Fractionator Overhead Light Naphtha Condenser
		E-205E – FCCU Fractionator Overhead Light Naphtha Condenser
		E-205F – FCCU Fractionator Overhead Light Naphtha Condenser
		E-210A – FCCU Fractionator Wet Gas Condenser
		E-210B – FCCU Fractionator Wet Gas Condenser
		E-210C – FCCU Fractionator Wet Gas Condenser
		E-210D – FCCU Fractionator Wet Gas Condenser
		E-217A – FCCU Debutanizer Gasoline Product Cooler
		E-217B – FCCU Debutanizer Gasoline Product Cooler

a. Each affected source shall comply with NESHAP, 40 CFR Part 63, Subpart CC. The permittee shall comply with the applicable sections for each affected source including but not limited to: [40 CFR §§ 63.640-656]
   i. § 63.642 General Standards - (c-g), (i), (k), & (l);
   ii. § 63.654 Heat Exchange Systems – (a-g);
   iii. § 63.655 Reporting and Recordkeeping Requirements - (d-i).

EUG 42B Ceramic Induced Draft Cooling Tower, 1,200-hp, 273 MMBTUH, 8,500 GPM, Heat Exchangers W/HAP Concentration >5%, W/Pressure > Cooling Water Pressure, & Subject to NESHAP, Subpart CC. These heat exchangers do not have specific limitations, except to comply with the applicable requirements of the NESHAP.

EU	Point	Heat Exchangers
C-1501	P193	E-10043 - Vent Gas Condenser
		E-10044 - Vent Gas Condenser
		E-101 – Fractionator Heavy Naphtha Product Cooler
		E-111A – Fractionator Light Naphtha Condenser
		E-111B – Fractionator Light Naphtha Condenser
		E-111C – Fractionator Light Naphtha Condenser
		E-111D – Fractionator Light Naphtha Condenser
		E-113A – Fractionator Light Naphtha Condenser
		E-113B – Fractionator Light Naphtha Condenser
		E-113C – Fractionator Light Naphtha Condenser
		E-113D – Fractionator Light Naphtha Condenser
		E-116A – Fractionator Heavy Naphtha Product Cooler
		E-116B – Fractionator Heavy Naphtha Product Cooler
		E-116C – Fractionator Heavy Naphtha Product Cooler
		E-116D – Fractionator Heavy Naphtha Product Cooler
		E-304A – Debutanizer Naphtha Product Cooler
		E-304B – Debutanizer Naphtha Product Cooler
		E-304C – Debutanizer Naphtha Product Cooler
		E-403 – Light Naphtha Condenser
		E-405A – Splitter Naphtha Product Cooler
		E-411A – Naphtha Reformer Reactor Product Cooler
		E-411B – Naphtha Reformer Reactor Product Cooler
		E-416 – Debutanizer Heavy Reformate Product Cooler
		E-418 – Debutanizer Light Reformate Product Cooler

a. Each affected source shall comply with NESHAP, 40 CFR Part 63, Subpart CC. The permittee shall comply with the applicable sections for each affected source including but not limited to: [40 CFR §§ 63.640-656]
   i. § 63.642 General Standards - (c-g), (i), (k), & (l);
   ii. § 63.654 Heat Exchange Systems – (a-g);
   iii. § 63.655 Reporting and Recordkeeping Requirements - (d-i).

EUG 42C Alkylation Induced Draft Cooling Tower, 700-hp, 248 MMBTUH, 16,000 GPM, Heat Exchangers W/HAP Concentration >5%, W/Pressure > Cooling Water Pressure, & Subject to NESHAP, Subpart CC. These heat exchangers do not have specific limitations, except to comply with the applicable requirements of the NESHAP.

EU	Point	Heat Exchangers
C-150005	P194	E-903A – Alkylate Product Cooler
		E-903B – Alkylate Product Cooler
		E-907A – Reactor Alkylate Recycle Cooler
		E-907B – Reactor Alkylate Recycle Cooler
		E-907C – Reactor Alkylate Recycle Cooler
		E-907D – Reactor Alkylate Recycle Cooler
		R-901 – Alkylation Reactor/Heat Exchanger
		R-902 – Alkylation Reactor/Heat Exchanger

a. Each affected source shall comply with NESHAP, 40 CFR Part 63, Subpart CC. The permittee shall comply with the applicable sections for each affected source including but not limited to: [40 CFR §§ 63.640-656]
   i. § 63.642 General Standards - (c-g), (i), (k), & (l);
   ii. § 63.654 Heat Exchange Systems – (a-g);
   iii. § 63.655 Reporting and Recordkeeping Requirements - (d-i).

EUG 42D STG Induced Draft Cooling Tower, 600-hp, 214 MMBTUH, 25,800 GPM, Heat Exchangers W/HAP Concentration >5%, W/Pressure > Cooling Water Pressure, & Subject to NESHAP, Subpart CC. These heat exchangers do not have specific limitations, except to comply with the applicable requirements of the NESHAP.

EU	Point	Heat Exchangers
C-150006	P195	E-81004 – FGR Naphtha Slop Product Cooler
		E-10043 - Vent Gas Condenser
		E-10044 - Vent Gas Condenser
		E-101 – Fractionator Heavy Naphtha Product Cooler
		E-111A – Fractionator Light Naphtha Condenser
		E-111B – Fractionator Light Naphtha Condenser
		E-111C – Fractionator Light Naphtha Condenser
		E-111D – Fractionator Light Naphtha Condenser
		E-113A – Fractionator Light Naphtha Condenser
		E-113B – Fractionator Light Naphtha Condenser
		E-113C – Fractionator Light Naphtha Condenser
		E-113D – Fractionator Light Naphtha Condenser
		E-116A – Fractionator Heavy Naphtha Product Cooler
		E-116B – Fractionator Heavy Naphtha Product Cooler
		E-116C – Fractionator Heavy Naphtha Product Cooler
		E-116D – Fractionator Heavy Naphtha Product Cooler

EU	Point	Heat Exchangers
		E-304A – Debutanizer Naphtha Product Cooler
		E-304B – Debutanizer Naphtha Product Cooler
		E-304C – Debutanizer Naphtha Product Cooler
		E-403 – Light Naphtha Condenser
		E-405A – Splitter Naphtha Product Cooler
		E-411A – Naphtha Reformer Reactor Product Cooler
		E-411B – Naphtha Reformer Reactor Product Cooler
		E-416 – Debutanizer Heavy Reformate Product Cooler
		E-418 – Debutanizer Light Reformate Product Cooler

a. Each affected source shall comply with NESHAP, 40 CFR Part 63, Subpart CC. The permittee shall comply with the applicable sections for each affected source including but not limited to: [40 CFR §§ 63.640-656]
   i. § 63.642 General Standards - (c-g), (i), (k), & (l);
   ii. § 63.654 Heat Exchange Systems – (a-g);
   iii. § 63.655 Reporting and Recordkeeping Requirements - (d-i).

EUG 43 Bypass Pressure Control Valves (BPCV) & Bypass Block Valves (BBV) Subject to NESHAP, Subpart UUU. These bypasses do not have specific limitations, except to comply with the applicable requirements of the NESHAP.

EU	Point	Sources Routed to Flare Gas Recovery System
PV5401A BPCV	P196	Amine Acid Gas Bypass of #1 SRU
PV824030 BPCV	P197	#1 SWS Acid Gas Bypass of SRU(s)
PV834015 BPCV	P198	#2 SWS Acid Gas Bypass of SRU(s)
PV57409 BPCV	P199	Amine Acid Gas Bypass of #2 SRU
PV58448 BPCV	P200	Amine Acid Gas Bypass of #2 SRU
PSV-55470 4” BBV	P201	4” BBV Around PSV-55470
PSV-55471 4” BBV	P202	4” BBV Around PSV-55471
PSV-55423 1.5” BBV	P203	1.5” BBV Around PSV-55423
PV-55423 2” BBV	P204	2” BBV at Discharge of PV-55423
PSV-55462 2” BBV	P205	2” BBV Around PSV-55462
PSV-55305 1” BBV	P206	1” BBV Around PSV-55305
PSV-56441 2” BBV	P207	2” BBV Around PSV-56441
PSV-56442 1.5” BBV	P208	1.5” BBV Around PSV-56442
PSV-56443 1.5” BBV	P209	1.5” BBV Around PSV-56443
PSV-565754 2” BBV	P210	2” BBV Around PSV-565754
PSV-57465 1.5” BBV	P211	1.5” BBV Around PSV-57465
PSV-57461 3” BBV	P212	3” BBV Around PSV-57461
PSV-57409 3” BBV	P213	3” BBV Around PSV-57409
PSV-58406 4” BBV	P214	4” BBV Around PSV-58406
PSV-58438 3” BBV	P215	3” BBV Around PSV-58438
PSV-584064 1.5” BBV	P216	1.5” BBV Around PSV-584064

EU	Point	Sources Routed to Flare Gas Recovery System
V-5804 3” BBV	P217	3” BBV on V-5804
PSV-584067 1” BBV	P218	1” BBV Around PSV-584067
V-82001 3” BBV	P219	3” BBV on V-82001
PSV-824029 3” BBV	P220	3” BBV Around PSV-824029
V-83001 4” BBV	P221	4” BBV on V-83001
PSV-834015B 4” BBV	P222	4” BBV Around PSV-834015B
PSV-834014 2” BBV	P223	2” BBV Around PSV-834014
PSV-834022 1.5” BBV	P224	1.5” BBV Around PSV-834022
CCR Scrubber BBV	P225	CCR Regenerator Flue Gas Bypass Atmospheric Vent Maintained Under Car Seal

a. EU bypass is subject to NESHAP, Subpart UUU and shall comply with all applicable requirements including but not limited to: [40 CFR §§ 60.1560-1579]

i. § 63.1560 What is the purpose of this subpart?
ii. § 63.1561 Am I subject to this subpart?
iii. § 63.1562 What parts of my plant are covered by this subpart?
iv. § 63.1563 When do I have to comply with this subpart?
v. § 63.1566 What are my requirements for organic HAP emissions from catalytic reforming units?
vi. § 63.1567 What are my requirements for inorganic HAP emissions from catalytic reforming units?
vii. § 63.1569 What are my requirements for HAP emissions from bypass lines?
viii. § 63.1570 What are my general requirements for complying with this subpart?
ix. § 63.1572 What are my monitoring installation, operation, and maintenance requirements?
x. § 63.1574 What notifications must I submit and when?
xi. § 63.1575 What reports must I submit and when?
xii. § 63.1576 What records must I keep, in what form, and for how long?
xiii. § 63.1577 What parts of the General Provisions apply to me?

<u>Insignificant Activities (ISA)</u>

PMA Unit Polymer Unloading & Storage Silos
Company Vehicle/Equipment Fueling Station
RCRA North Yard Bin Storage Area
DHDS Catalyst Change-Out Area
CFHT Catalyst Change-Out Area
Hydrocracker Catalyst Change-Out Area
SRU Catalyst Change-Out Area
NHT Catalyst Change-Out Area
Reformer Catalyst Change-Out Area
Bensat Catalyst Change-Out Area
East Bundle Pad
West Bundle Pad
Tank Truck Crude Oil Unloading Station

Other sources/equipment meeting definition of ISA in OAC 252:100-8-2

Storage Vessels that Qualify as Insignificant Activities/Trivial Activities

EU	Contents	Barrels
T-451	Perchloroethylene	320
T-551	MDEA	91
T-811	Spent Caustic	1,007
T-812	Spent Caustic	1,007
T-813	Spent Caustic	1,007
T-814	Spent Caustic	1,007
T-8803	RCRA Remediation Trench Oil/Water	202
T-8804	RCRA Remediation Trench Oil	202
T-210001	Polymer Asphalt	19
T-210002	10 % H_3PO_4	9,517
TK-13005	Fuel Additives	49
TK-13007	Fuel Additives	49
TK-13008	Fuel Additives	49
TK-13009	Fuel Additives	49
V-523	Amine	91
V-815	Wastewater Centrifuge Solids	1,731
JFP1	Refinery Vehicle Refueling Gasoline	52
JFP2	Refinery Vehicle Refueling Red Dye	11
JFP3	Refinery Vehicle Refueling Diesel (Off-Road)	22
TK-90001	Spent KOH/KF	1,678
EWCPTK-1	Diesel Fuel	21
EWCPTK-2	Diesel Fuel	21
EWCPTK-3	Diesel Fuel	21
T-1191	Slop Oil	200

<u>Trivial Activities (TA)</u>

South 40 WWTP Ponds
Treated Process Water Pond 002
Treated Process Water Pond 003
Treated Process Water Northwest Pond
Refinery Internal Firefighting Training Area
Maintenance Department Cutting/Grinding/Welding Activities
Chigger Hill Equipment Fabrication and De-Commissioning/Lay Down Yard
Warehouse Yard Bulk-Chemical/Tote/Cylinder/Drum Storage Yard
Light Product Loading Terminal Fuel Additive Storage Totes/Tanks
Steam Turbine Generators Cooling Tower
Aerosol Can Disposal Station
Gasoline blender QA/QC operations
QA/QC Laboratories
Land Treatment Unit
Other approved sources meeting definition of TA in OAC 252:100-8-2

3. All affected fuel-burning equipment shall be fired with natural gas or fuel gas as defined in § 60.101(d) except as specified elsewhere in the Specific Conditions. [OAC 252:100-19]

4. The following records shall be maintained on-site to verify Insignificant Activities. No recordkeeping is required for those operations, which qualify as Trivial Activities.

[OAC 252:100-8-6(a)(3) & 100-43]

a. For fluid storage tanks with a capacity of less than 39,894 gallons and a true vapor pressure less than 1.5 psia: records of the capacity of the tanks and the contents.
b. For fuel storage/dispensing equipment operated solely for facility owned vehicles: records of the amount of fuel dispensed (gallons/day, monthly average).
c. For activities (except for trivial activities) that have the potential to emit less than 5 TPY (actual) of any criteria pollutant: the type of activity and the amount of emissions or a surrogate measure of the activity (annual).

5. The Refinery is subject to NESHAP, 40 CFR Part 61, Subpart FF and all affected equipment shall comply with all applicable requirements. [40 CFR §§ 61.340-359]

a. § 61.342 Standards: General.
b. § 61.343 Standards: Tanks.
c. § 61.344 Standards: Surface Impoundments.
d. § 61.345 Standards: Containers.
e. § 61.346 Standards: Individual drain systems.
f. § 61.347 Standards: Oil-water separators.
g. § 61.348 Standards: Treatment processes.
h. § 61.349 Standards: Closed-vent systems and control devices.
i. § 61.350 Standards: Delay of repair.
j. § 61.351 Alternative standards for tanks.
k. § 61.352 Alternative standards for oil-water separators.
l. § 61.353 Alternative means of emission limitation.
m. § 61.354 Monitoring of operations.
n. § 61.355 Test methods, procedures, and compliance provisions.
o. § 61.356 Recordkeeping requirements.
p. § 61.357 Reporting requirements.

6. Certain equipment within the refinery is subject to NESHAP, 40 CFR Part 63, Subpart CC and all affected equipment shall comply with all applicable requirements.

[40 CFR §§ 63.640-656]

a. § 63.642 General Standards
b. § 63.643 Miscellaneous Process Vent Provisions
c. § 63.644 Monitoring for Miscellaneous Process Vents
d. § 63.645 Test Methods and Procedures for Miscellaneous Process Vents
e. § 63.646 Storage Vessel Provisions

f. § 63.647 Wastewater Provisions
g. § 63.648 Equipment Leak Standards
h. § 63.649 Alternative Means of Emission Limitation: Connectors in Gas/Vapor Service and Light Liquid Service
i. § 63.650 Gasoline Loading Rack Provisions
j. § 63.652 Emissions Averaging Provisions
k. § 63.653 Monitoring, Recordkeeping, and Implementation Plan for Emissions Averaging
l. § 63.654 Heat Exchange Systems
m. § 63.655 Reporting and Recordkeeping Requirements
n. § 63.658 Fenceline Monitoring Provisions
o. § 63.660 Storage Vessel Provisions
p. § 63.670 Requirements for Flare Control Devices
q. § 63.671 Requirements for Flare Monitoring Systems
r. The permittee shall comply with the provisions of 40 CFR Part 63 Subpart A as specified in Appendix to Subpart CC, Table 6.

7. Site remediation activities at the refinery are subject to NESHAP, 40 CFR Part 63, Subpart GGGGG and the refinery shall comply with all applicable requirements including but not limited to: [40 CFR §§ 63.7880-7957]

a. Site remediation is not subject to 40 CFR Part 63, Subpart GGGGG, except for the recordkeeping requirements specified in § 63.7881(c), if the site remediation meets the all of the conditions in .§ 63.7881(c)(1) through (3). [§ 63.7881(c)]
   i. Before beginning site remediation, you shall determine, for the remediation material that you will excavate, extract, pump, or otherwise remove during your site remediation, that the total quantity of HAP listed in Table 1 of 40 CFR Part 63, Subpart GGGGG, which is contained in the material is less than 1 megagram per year (Mg/yr). [§ 63.7881(c)(1)]
   ii. You shall prepare and maintain at your facility written documentation to support your determination of the total HAP quantity used to demonstrate compliance with § 63.7881(c)(1). This documentation must include a description of your methodology and data you used for determining the total HAP content of the material. [§ 63.7881(c)(2)]
   iii. This exemption may be applied to more than one site remediation at your facility provided that the total quantity of the HAP listed in Table 1 of 40 CFR Part 63, Subpart GGGGG for all of your site remediations exempted under this provision is less than 1 Mg/yr. [§ 63.7881(c)(3)]

8. The permittee shall comply with all applicable requirements of NESHAP, Subpart DDDDD, Industrial, Commercial, and Institutional Boilers and Process Heaters, including but not limited to: [40 CFR §§ 63.7480-7575]

<u>What This Subpart Covers</u>

a. § 63.7480 What is the purpose of this subpart?

b. § 63.7485 Am I subject to this subpart?
c. § 63.7490 What is the affected source of this subpart?
d. § 63.7491 Are any boilers or process heaters not subject to this subpart?
e. § 63.7495 When do I have to comply with this subpart?

<u>Emission Limitations and Work Practice Standards</u>

f. § 63.7499 What are the subcategories of boilers and process heaters?
g. § 63.7500 What emission limitations, work practice standards, and operating limits must I meet?
h. § 63.7501 Affirmative Defense for Violation of Emission Standards During Malfunction.

<u>General Compliance Requirements</u>

i. § 63.7505 What are my general requirements for complying with this subpart?

<u>Testing, Fuel Analyses, and Initial Compliance Requirements</u>

j. § 63.7510 What are my initial compliance requirements and by what date must I conduct them?
k. § 63.7515 When must I conduct subsequent performance tests, fuel analyses, or tune-ups?
l. § 63.7520 What stack tests and procedures must I use?
m. § 63.7521 What fuel analyses, fuel specification, and procedures must I use?
n. § 63.7522 Can I use emissions averaging to comply with this subpart?
o. § 63.7525 What are my monitoring, installation, operation, and maintenance requirements?
p. § 63.7530 How do I demonstrate initial compliance with the emission limitations, fuel specifications and work practice standards?
q. § 63.7533 Can I use efficiency credits earned from implementation of energy conservation measures to comply with this subpart?

<u>Continuous Compliance Requirements</u>

r. § 63.7535 Is there a minimum amount of monitoring data I must obtain?
s. § 63.7540 How do I demonstrate continuous compliance with the emission limitations, fuel specifications and work practice standards?
t. § 63.7541 How do I demonstrate continuous compliance under the emissions averaging provision?

<u>Notification, Reports, and Records</u>

u. § 63.7545 What notifications must I submit and when?
v. § 63.7550 What reports must I submit and when?
w. § 63.7555 What records must I keep?
x. § 63.7560 In what form and how long must I keep my records?

<u>Other Requirements and Information</u>

y. § 63.7565 What parts of the General Provisions apply to me?
z. § 63.7570 Who implements and enforces this subpart?
aa. § 63.7575 What definitions apply to this subpart?

9. Unless 12 consecutive months of data has been collected to determine the 12-month rolling totals and averages applicable to the facility, the facility shall fill the missing data for the previous months with an estimated average monthly figure based on the applicable rolling total or average

divided by 12. If there exists enough data to determine the values for the previous months, it can be used to determine the applicable 12-month rolling totals or averages.

[OAC 252:100-8-6(a)(3) & 100-43]

10. For any modification using "projected actual emissions" as defined in OAC 252:100-8-31, the permittee shall document and maintain a record of the information required by OAC 252:100-8-36.2(c)(1)(A) through (C). The permittee shall monitor the emissions of any regulated NSR pollutant that could increase as a result of the modification and that is emitted by any emissions unit identified; and calculate and maintain a record of the annual emissions, in TPY on a calendar year basis, for a period of 5 years following resumption of regular operations after the modification, or for a period of 10 years following resumption of regular operations after the modification if it increases the design capacity or potential to emit of the affected emissions unit. The permittee shall submit a report to the Director if the annual emissions, in TPY, from the modification, exceed the baseline actual emissions (as documented and maintained) by an amount that is significant for that regulated NSR pollutant, and if such emissions differ from the preconstruction projection for that modification. The report shall be submitted to the AQD within 60 days after the end of each year in which the exceedances or difference occurred. The report shall contain the information required by OAC 252:100-8-36.2(c)(5)(A) through (C). If the permittee materially fails to comply with these provisions, then the calendar year emissions are presumed to equal the source's potential to emit.

[OAC 252:100-8-36.2(c)]

11. The permittee shall maintain records as specified in Specific Condition 1 and 2 including but not limited to those listed below. These records shall be maintained on-site for at least five years after the date of recording and shall be provided to regulatory personnel upon request.

[OAC 252:100-8-6(a)(3) & 100-43]

a. Records showing compliance with 12-month rolling totals (monthly) and 12-month rolling averages (daily and monthly) established in Specific Conditions 1 and 2.
b. Records showing compliance with emission limits (monthly) established in Specific Conditions 1 and 2.
c. MTVP or VP for EUG 1 through 4 (as applicable).
d. Temperature of materials stored in T-153 & T-156 (daily).
e. Heater fuel usage (monthly) and heat content (quarterly) for EUG 9, 10 & 11.
f. Waste gas per barrel of asphalt for EUG 16 (quarterly).
g. Throughput and temperatures for EUG 16 (daily).
h. Throughputs for EUG 17 and 27 (daily and monthly).
i. The FCCU NO_X, CO, and SO_2 CEM data, annual emissions, average concentration, and average stack flow (monthly).
j. The FCCU WGS liquid flow rate, gas flow rate and temperature, liquid to gas ratio, pressure drop, and pH (24-hour averages).
k. The FCCU feedstock nitrogen content (daily/weekly)
l. The FCCU coke burn rate (daily average).
m. NO_X CEM data for EU H-102A and H-102B (EUG 9).

n. The calculated HCN emissions (daily).
o. The hours of operation of the EU in EUG 20, 22, and 40, and the reason for operation of EUG 20 (monthly and 12-month rolling totals).
p. The throughput of EUG 23 (daily) and the H_2S concentration of the gases from the loading operations (monthly).
q. The catalyst recirculation rate and the feedstock sulfur content of the CCR (quarterly).
r. The CO emission testing for the CCR (quarterly or semi-annual).
s. The Cat_Hop WS liquid flow rate, gas flow rate and temperature, liquid to gas ratio, pressure drop, and pH (24-hour averages, if applicable).
t. The flow rate and VOC concentration of the WWTP Bioreactor atmospheric vent when the bioreactors are vented to the atmosphere (daily).
u. The WWTP Incinerator combustion zone temperature (daily) when gases are being routed to the incinerator for combustion.
v. The flow rate and ammonia concentration of the WWTP being sent to the WWTP incinerator (monthly or quarterly) when gases are being routed to the incinerator for combustion.
w. Temperature of the asphalt in the storage vessels from which asphalt is being loaded (daily).
x. Visible emission observations (date, time, and reading).
y. Records required by 40 CFR Part 60, NSPS, Subparts A, Db, Dc, Kb, J, Ja, GGG, GGGa, QQQ, IIII and JJJJ; 40 CFR Part 61, NESHAP, Subparts A and FF; and 40 CFR Part 63, NESHAP, Subparts A, CC, UUU, ZZZZ, DDDDD, and LLLLL.
z. Records required by Specific Condition 10 for modifications using "projected actual emissions."

12. When monitoring shows an exceedance of any of the limits of Specific Condition No. 1 or 2, the owner or operator shall comply with the provisions of OAC 252:100-9 for excess emissions where applicable. [OAC 252:100-9]

13. No later than 30 days after each anniversary date of the issuance of the original Part 70 operating permit, the permittee shall submit to Air Quality Division of DEQ, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of the Part 70 operating permit. [OAC 252:100-8-6(c)(5)(A) & (D)]

14. This permit supersedes and replaces Air Quality operating Permit No. 2012-1523-TVR (M-1). On issuance of this permit, Permit No. 2012-1523-TVR (M-1) will be cancelled.

15. The facility shall comply with all applicable requirements of any federal consent decree.

MAJOR SOURCE AIR QUALITY PERMIT
STANDARD CONDITIONS
(June 21, 2016)

SECTION I. DUTY TO COMPLY

A. This is a permit to operate / construct this specific facility in accordance with the federal Clean Air Act (42 U.S.C. 7401, et al.) and under the authority of the Oklahoma Clean Air Act and the rules promulgated there under. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

B. The issuing Authority for the permit is the Air Quality Division (AQD) of the Oklahoma Department of Environmental Quality (DEQ). The permit does not relieve the holder of the obligation to comply with other applicable federal, state, or local statutes, regulations, rules, or ordinances. [Oklahoma Clean Air Act, 27A O.S. § 2-5-112]

C. The permittee shall comply with all conditions of this permit. Any permit noncompliance shall constitute a violation of the Oklahoma Clean Air Act and shall be grounds for enforcement action, permit termination, revocation and reissuance, or modification, or for denial of a permit renewal application. All terms and conditions are enforceable by the DEQ, by the Environmental Protection Agency (EPA), and by citizens under section 304 of the Federal Clean Air Act (excluding state-only requirements). This permit is valid for operations only at the specific location listed.
[40 C.F.R. §70.6(b), OAC 252:100-8-1.3 and OAC 252:100-8-6(a)(7)(A) and (b)(1)]

D. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit. However, nothing in this paragraph shall be construed as precluding consideration of a need to halt or reduce activity as a mitigating factor in assessing penalties for noncompliance if the health, safety, or environmental impacts of halting or reducing operations would be more serious than the impacts of continuing operations. [OAC 252:100-8-6(a)(7)(B)]

SECTION II. REPORTING OF DEVIATIONS FROM PERMIT TERMS

A. Any exceedance resulting from an emergency and/or posing an imminent and substantial danger to public health, safety, or the environment shall be reported in accordance with Section XIV (Emergencies). [OAC 252:100-8-6(a)(3)(C)(iii)(I) & (II)]

B. Deviations that result in emissions exceeding those allowed in this permit shall be reported consistent with the requirements of OAC 252:100-9, Excess Emission Reporting Requirements.
[OAC 252:100-8-6(a)(3)(C)(iv)]

C. Every written report submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F.
[OAC 252:100-8-6(a)(3)(C)(iv)]

SECTION III. MONITORING, TESTING, RECORDKEEPING & REPORTING

A. The permittee shall keep records as specified in this permit. These records, including monitoring data and necessary support information, shall be retained on-site or at a nearby field office for a period of at least five years from the date of the monitoring sample, measurement, report, or application, and shall be made available for inspection by regulatory personnel upon request. Support information includes all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. Where appropriate, the permit may specify that records may be maintained in computerized form.

[OAC 252:100-8-6 (a)(3)(B)(ii), OAC 252:100-8-6(c)(1), and OAC 252:100-8-6(c)(2)(B)]

B. Records of required monitoring shall include:
(1) the date, place and time of sampling or measurement;
(2) the date or dates analyses were performed;
(3) the company or entity which performed the analyses;
(4) the analytical techniques or methods used;
(5) the results of such analyses; and
(6) the operating conditions existing at the time of sampling or measurement.

[OAC 252:100-8-6(a)(3)(B)(i)]

C. No later than 30 days after each six (6) month period, after the date of the issuance of the original Part 70 operating permit or alternative date as specifically identified in a subsequent Part 70 operating permit, the permittee shall submit to AQD a report of the results of any required monitoring. All instances of deviations from permit requirements since the previous report shall be clearly identified in the report. Submission of these periodic reports will satisfy any reporting requirement of Paragraph E below that is duplicative of the periodic reports, if so noted on the submitted report. [OAC 252:100-8-6(a)(3)(C)(i) and (ii)]

D. If any testing shows emissions in excess of limitations specified in this permit, the owner or operator shall comply with the provisions of Section II (Reporting Of Deviations From Permit Terms) of these standard conditions. [OAC 252:100-8-6(a)(3)(C)(iii)]

E. In addition to any monitoring, recordkeeping or reporting requirement specified in this permit, monitoring and reporting may be required under the provisions of OAC 252:100-43, Testing, Monitoring, and Recordkeeping, or as required by any provision of the Federal Clean Air Act or Oklahoma Clean Air Act. [OAC 252:100-43]

F. Any Annual Certification of Compliance, Semi Annual Monitoring and Deviation Report, Excess Emission Report, and Annual Emission Inventory submitted in accordance with this permit shall be certified by a responsible official. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete."

[OAC 252:100-8-5(f), OAC 252:100-8-6(a)(3)(C)(iv), OAC 252:100-8-6(c)(1), OAC 252:100-9-7(e), and OAC 252:100-5-2.1(f)]

G. Any owner or operator subject to the provisions of New Source Performance Standards ("NSPS") under 40 CFR Part 60 or National Emission Standards for Hazardous Air Pollutants ("NESHAPs") under 40 CFR Parts 61 and 63 shall maintain a file of all measurements and other information required by the applicable general provisions and subpart(s). These records shall be maintained in a permanent file suitable for inspection, shall be retained for a period of at least five years as required by Paragraph A of this Section, and shall include records of the occurrence and duration of any start-up, shutdown, or malfunction in the operation of an affected facility, any malfunction of the air pollution control equipment; and any periods during which a continuous monitoring system or monitoring device is inoperative.
[40 C.F.R. §§60.7 and 63.10, 40 CFR Parts 61, Subpart A, and OAC 252:100, Appendix Q]

H. The permittee of a facility that is operating subject to a schedule of compliance shall submit to the DEQ a progress report at least semi-annually. The progress reports shall contain dates for achieving the activities, milestones or compliance required in the schedule of compliance and the dates when such activities, milestones or compliance was achieved. The progress reports shall also contain an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted. [OAC 252:100-8-6(c)(4)]

I. All testing must be conducted under the direction of qualified personnel by methods approved by the Division Director. All tests shall be made and the results calculated in accordance with standard test procedures. The use of alternative test procedures must be approved by EPA. When a portable analyzer is used to measure emissions it shall be setup, calibrated, and operated in accordance with the manufacturer's instructions and in accordance with a protocol meeting the requirements of the "AQD Portable Analyzer Guidance" document or an equivalent method approved by Air Quality.
[OAC 252:100-8-6(a)(3)(A)(iv), and OAC 252:100-43]

J. The reporting of total particulate matter emissions as required in Part 7 of OAC 252:100-8 (Permits for Part 70 Sources), OAC 252:100-19 (Control of Emission of Particulate Matter), and OAC 252:100-5 (Emission Inventory), shall be conducted in accordance with applicable testing or calculation procedures, modified to include back-half condensables, for the concentration of particulate matter less than 10 microns in diameter (PM_{10}). NSPS may allow reporting of only particulate matter emissions caught in the filter (obtained using Reference Method 5).

K. The permittee shall submit to the AQD a copy of all reports submitted to the EPA as required by 40 C.F.R. Part 60, 61, and 63, for all equipment constructed or operated under this permit subject to such standards. [OAC 252:100-8-6(c)(1) and OAC 252:100, Appendix Q]

SECTION IV. COMPLIANCE CERTIFICATIONS

A. No later than 30 days after each anniversary date of the issuance of the original Part 70 operating permit or alternative date as specifically identified in a subsequent Part 70 operating permit, the permittee shall submit to the AQD, with a copy to the US EPA, Region 6, a certification of compliance with the terms and conditions of this permit and of any other applicable requirements which have become effective since the issuance of this permit.
[OAC 252:100-8-6(c)(5)(A), and (D)]

B. The compliance certification shall describe the operating permit term or condition that is the basis of the certification; the current compliance status; whether compliance was continuous or intermittent; the methods used for determining compliance, currently and over the reporting period. The compliance certification shall also include such other facts as the permitting authority may require to determine the compliance status of the source.

[OAC 252:100-8-6(c)(5)(C)(i)-(v)]

C. The compliance certification shall contain a certification by a responsible official as to the results of the required monitoring. This certification shall be signed by a responsible official, and shall contain the following language: "I certify, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete." [OAC 252:100-8-5(f) and OAC 252:100-8-6(c)(1)]

D. Any facility reporting noncompliance shall submit a schedule of compliance for emissions units or stationary sources that are not in compliance with all applicable requirements. This schedule shall include a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance with any applicable requirements for which the emissions unit or stationary source is in noncompliance. This compliance schedule shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the emissions unit or stationary source is subject. Any such schedule of compliance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it is based, except that a compliance plan shall not be required for any noncompliance condition which is corrected within 24 hours of discovery.

[OAC 252:100-8-5(e)(8)(B) and OAC 252:100-8-6(c)(3)]

SECTION V. REQUIREMENTS THAT BECOME APPLICABLE DURING THE PERMIT TERM

The permittee shall comply with any additional requirements that become effective during the permit term and that are applicable to the facility. Compliance with all new requirements shall be certified in the next annual certification. [OAC 252:100-8-6(c)(6)]

SECTION VI. PERMIT SHIELD

A. Compliance with the terms and conditions of this permit (including terms and conditions established for alternate operating scenarios, emissions trading, and emissions averaging, but excluding terms and conditions for which the permit shield is expressly prohibited under OAC 252:100-8) shall be deemed compliance with the applicable requirements identified and included in this permit. [OAC 252:100-8-6(d)(1)]

B. Those requirements that are applicable are listed in the Standard Conditions and the Specific Conditions of this permit. Those requirements that the applicant requested be determined as not applicable are summarized in the Specific Conditions of this permit. [OAC 252:100-8-6(d)(2)]

SECTION VII. ANNUAL EMISSIONS INVENTORY & FEE PAYMENT

The permittee shall file with the AQD an annual emission inventory and shall pay annual fees based on emissions inventories. The methods used to calculate emissions for inventory purposes shall be based on the best available information accepted by AQD.
[OAC 252:100-5-2.1, OAC 252:100-5-2.2, and OAC 252:100-8-6(a)(8)]

SECTION VIII. TERM OF PERMIT

A. Unless specified otherwise, the term of an operating permit shall be five years from the date of issuance. [OAC 252:100-8-6(a)(2)(A)]

B. A source's right to operate shall terminate upon the expiration of its permit unless a timely and complete renewal application has been submitted at least 180 days before the date of expiration. [OAC 252:100-8-7.1(d)(1)]

C. A duly issued construction permit or authorization to construct or modify will terminate and become null and void (unless extended as provided in OAC 252:100-8-1.4(b)) if the construction is not commenced within 18 months after the date the permit or authorization was issued, or if work is suspended for more than 18 months after it is commenced. [OAC 252:100-8-1.4(a)]

D. The recipient of a construction permit shall apply for a permit to operate (or modified operating permit) within 180 days following the first day of operation. [OAC 252:100-8-4(b)(5)]

SECTION IX. SEVERABILITY

The provisions of this permit are severable and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.
[OAC 252:100-8-6 (a)(6)]

SECTION X. PROPERTY RIGHTS

A. This permit does not convey any property rights of any sort, or any exclusive privilege.
[OAC 252:100-8-6(a)(7)(D)]

B. This permit shall not be considered in any manner affecting the title of the premises upon which the equipment is located and does not release the permittee from any liability for damage to persons or property caused by or resulting from the maintenance or operation of the equipment for which the permit is issued. [OAC 252:100-8-6(c)(6)]

SECTION XI. DUTY TO PROVIDE INFORMATION

A. The permittee shall furnish to the DEQ, upon receipt of a written request and within sixty (60) days of the request unless the DEQ specifies another time period, any information that the DEQ may request to determine whether cause exists for modifying, reopening, revoking, reissuing, terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the DEQ copies of records required to be kept by the permit.

[OAC 252:100-8-6(a)(7)(E)]

B. The permittee may make a claim of confidentiality for any information or records submitted pursuant to 27A O.S. § 2-5-105(18). Confidential information shall be clearly labeled as such and shall be separable from the main body of the document such as in an attachment.

[OAC 252:100-8-6(a)(7)(E)]

C. Notification to the AQD of the sale or transfer of ownership of this facility is required and shall be made in writing within thirty (30) days after such sale or transfer.

[Oklahoma Clean Air Act, 27A O.S. § 2-5-112(G)]

SECTION XII. REOPENING, MODIFICATION & REVOCATION

A. The permit may be modified, revoked, reopened and reissued, or terminated for cause. Except as provided for minor permit modifications, the filing of a request by the permittee for a permit modification, revocation and reissuance, termination, notification of planned changes, or anticipated noncompliance does not stay any permit condition.

[OAC 252:100-8-6(a)(7)(C) and OAC 252:100-8-7.2(b)]

B. The DEQ will reopen and revise or revoke this permit prior to the expiration date in the following circumstances: [OAC 252:100-8-7.3 and OAC 252:100-8-7.4(a)(2)]

(1) Additional requirements under the Clean Air Act become applicable to a major source category three or more years prior to the expiration date of this permit. No such reopening is required if the effective date of the requirement is later than the expiration date of this permit.
(2) The DEQ or the EPA determines that this permit contains a material mistake or that the permit must be revised or revoked to assure compliance with the applicable requirements.
(3) The DEQ or the EPA determines that inaccurate information was used in establishing the emission standards, limitations, or other conditions of this permit. The DEQ may revoke and not reissue this permit if it determines that the permittee has submitted false or misleading information to the DEQ.
(4) DEQ determines that the permit should be amended under the discretionary reopening provisions of OAC 252:100-8-7.3(b).

C. The permit may be reopened for cause by EPA, pursuant to the provisions of OAC 100-8-7.3(d). [OAC 100-8-7.3(d)]

D. The permittee shall notify AQD before making changes other than those described in Section XVIII (Operational Flexibility), those qualifying for administrative permit amendments, or those defined as an Insignificant Activity (Section XVI) or Trivial Activity (Section XVII). The notification should include any changes which may alter the status of a "grandfathered source," as defined under AQD rules. Such changes may require a permit modification.

[OAC 252:100-8-7.2(b) and OAC 252:100-5-1.1]

E. Activities that will result in air emissions that exceed the trivial/insignificant levels and that are not specifically approved by this permit are prohibited. [OAC 252:100-8-6(c)(6)]

SECTION XIII. INSPECTION & ENTRY

A. Upon presentation of credentials and other documents as may be required by law, the permittee shall allow authorized regulatory officials to perform the following (subject to the permittee's right to seek confidential treatment pursuant to 27A O.S. Supp. 1998, § 2-5-105(17) for confidential information submitted to or obtained by the DEQ under this section):

(1) enter upon the permittee's premises during reasonable/normal working hours where a source is located or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;
(2) have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;
(3) inspect, at reasonable times and using reasonable safety practices, any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and
(4) as authorized by the Oklahoma Clean Air Act, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the permit.

[OAC 252:100-8-6(c)(2)]

SECTION XIV. EMERGENCIES

A. Any exceedance resulting from an emergency shall be reported to AQD promptly but no later than 4:30 p.m. on the next working day after the permittee first becomes aware of the exceedance. This notice shall contain a description of the emergency, the probable cause of the exceedance, any steps taken to mitigate emissions, and corrective actions taken.

[OAC 252:100-8-6 (a)(3)(C)(iii)(I) and (IV)]

B. Any exceedance that poses an imminent and substantial danger to public health, safety, or the environment shall be reported to AQD as soon as is practicable; but under no circumstance shall notification be more than 24 hours after the exceedance. [OAC 252:100-8-6(a)(3)(C)(iii)(II)]

C. An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under this permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error. [OAC 252:100-8-2]

D. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that: [OAC 252:100-8-6 (e)(2)]

(1) an emergency occurred and the permittee can identify the cause or causes of the emergency;

(2) the permitted facility was at the time being properly operated;
(3) during the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit.

E. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency shall have the burden of proof. [OAC 252:100-8-6(e)(3)]

F. Every written report or document submitted under this section shall be certified as required by Section III (Monitoring, Testing, Recordkeeping & Reporting), Paragraph F.
[OAC 252:100-8-6(a)(3)(C)(iv)]

SECTION XV. RISK MANAGEMENT PLAN

The permittee, if subject to the provision of Section 112(r) of the Clean Air Act, shall develop and register with the appropriate agency a risk management plan by June 20, 1999, or the applicable effective date. [OAC 252:100-8-6(a)(4)]

SECTION XVI. INSIGNIFICANT ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate individual emissions units that are either on the list in Appendix I to OAC Title 252, Chapter 100, or whose actual calendar year emissions do not exceed any of the limits below. Any activity to which a State or Federal applicable requirement applies is not insignificant even if it meets the criteria below or is included on the insignificant activities list.

(1) 5 tons per year of any one criteria pollutant.
(2) 2 tons per year for any one hazardous air pollutant (HAP) or 5 tons per year for an aggregate of two or more HAP's, or 20 percent of any threshold less than 10 tons per year for single HAP that the EPA may establish by rule.

[OAC 252:100-8-2 and OAC 252:100, Appendix I]

SECTION XVII. TRIVIAL ACTIVITIES

Except as otherwise prohibited or limited by this permit, the permittee is hereby authorized to operate any individual or combination of air emissions units that are considered inconsequential and are on the list in Appendix J. Any activity to which a State or Federal applicable requirement applies is not trivial even if included on the trivial activities list.
[OAC 252:100-8-2 and OAC 252:100, Appendix J]

SECTION XVIII. OPERATIONAL FLEXIBILITY

A. A facility may implement any operating scenario allowed for in its Part 70 permit without the need for any permit revision or any notification to the DEQ (unless specified otherwise in the permit). When an operating scenario is changed, the permittee shall record in a log at the facility the scenario under which it is operating. [OAC 252:100-8-6(a)(10) and (f)(1)]

B. The permittee may make changes within the facility that:

(1) result in no net emissions increases,
(2) are not modifications under any provision of Title I of the federal Clean Air Act, and
(3) do not cause any hourly or annual permitted emission rate of any existing emissions unit to be exceeded;

provided that the facility provides the EPA and the DEQ with written notification as required below in advance of the proposed changes, which shall be a minimum of seven (7) days, or twenty four (24) hours for emergencies as defined in OAC 252:100-8-6 (e). The permittee, the DEQ, and the EPA shall attach each such notice to their copy of the permit. For each such change, the written notification required above shall include a brief description of the change within the permitted facility, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable as a result of the change. The permit shield provided by this permit does not apply to any change made pursuant to this paragraph. [OAC 252:100-8-6(f)(2)]

SECTION XIX. OTHER APPLICABLE & STATE-ONLY REQUIREMENTS

A. The following applicable requirements and state-only requirements apply to the facility unless elsewhere covered by a more restrictive requirement:

(1) Open burning of refuse and other combustible material is prohibited except as authorized in the specific examples and under the conditions listed in the Open Burning Subchapter. [OAC 252:100-13]

(2) No particulate emissions from any fuel-burning equipment with a rated heat input of 10 MMBTUH or less shall exceed 0.6 lb/MMBTU. [OAC 252:100-19]

(3) For all emissions units not subject to an opacity limit promulgated under 40 C.F.R., Part 60, NSPS, no discharge of greater than 20% opacity is allowed except for: [OAC 252:100-25]

(a) Short-term occurrences which consist of not more than one six-minute period in any consecutive 60 minutes, not to exceed three such periods in any consecutive 24 hours. In no case shall the average of any six-minute period exceed 60% opacity;
(b) Smoke resulting from fires covered by the exceptions outlined in OAC 252:100-13-7;
(c) An emission, where the presence of uncombined water is the only reason for failure to meet the requirements of OAC 252:100-25-3(a); or
(d) Smoke generated due to a malfunction in a facility, when the source of the fuel producing the smoke is not under the direct and immediate control of the facility and the immediate constriction of the fuel flow at the facility would produce a hazard to life and/or property.

(4) No visible fugitive dust emissions shall be discharged beyond the property line on which the emissions originate in such a manner as to damage or to interfere with the use of

adjacent properties, or cause air quality standards to be exceeded, or interfere with the maintenance of air quality standards. [OAC 252:100-29]

(5) No sulfur oxide emissions from new gas-fired fuel-burning equipment shall exceed 0.2 lb/MMBTU. No existing source shall exceed the listed ambient air standards for sulfur dioxide. [OAC 252:100-31]

(6) Volatile Organic Compound (VOC) storage tanks built after December 28, 1974, and with a capacity of 400 gallons or more storing a liquid with a vapor pressure of 1.5 psia or greater under actual conditions shall be equipped with a permanent submerged fill pipe or with a vapor-recovery system. [OAC 252:100-37-15(b)]

(7) All fuel-burning equipment shall at all times be properly operated and maintained in a manner that will minimize emissions of VOCs. [OAC 252:100-37-36]

SECTION XX. STRATOSPHERIC OZONE PROTECTION

A. The permittee shall comply with the following standards for production and consumption of ozone-depleting substances: [40 CFR 82, Subpart A]

(1) Persons producing, importing, or placing an order for production or importation of certain class I and class II substances, HCFC-22, or HCFC-141b shall be subject to the requirements of §82.4;
(2) Producers, importers, exporters, purchasers, and persons who transform or destroy certain class I and class II substances, HCFC-22, or HCFC-141b are subject to the recordkeeping requirements at §82.13; and
(3) Class I substances (listed at Appendix A to Subpart A) include certain CFCs, Halons, HBFCs, carbon tetrachloride, trichloroethane (methyl chloroform), and bromomethane (Methyl Bromide). Class II substances (listed at Appendix B to Subpart A) include HCFCs.

B. If the permittee performs a service on motor (fleet) vehicles when this service involves an ozone-depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all applicable requirements. Note: The term “motor vehicle” as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term “MVAC” as used in Subpart B does not include the air-tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC-22 refrigerant. [40 CFR 82, Subpart B]

C. The permittee shall comply with the following standards for recycling and emissions reduction except as provided for MVACs in Subpart B: [40 CFR 82, Subpart F]

(1) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to § 82.156;
(2) Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to § 82.158;

(3) Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to § 82.161;
(4) Persons disposing of small appliances, MVACs, and MVAC-like appliances must comply with record-keeping requirements pursuant to § 82.166;
(5) Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to § 82.158; and
(6) Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to § 82.166.

SECTION XXI. TITLE V APPROVAL LANGUAGE

A. DEQ wishes to reduce the time and work associated with permit review and, wherever it is not inconsistent with Federal requirements, to provide for incorporation of requirements established through construction permitting into the Source's Title V permit without causing redundant review. Requirements from construction permits may be incorporated into the Title V permit through the administrative amendment process set forth in OAC 252:100-8-7.2(a) only if the following procedures are followed:

(1) The construction permit goes out for a 30-day public notice and comment using the procedures set forth in 40 C.F.R. § 70.7(h)(1). This public notice shall include notice to the public that this permit is subject to EPA review, EPA objection, and petition to EPA, as provided by 40 C.F.R. § 70.8; that the requirements of the construction permit will be incorporated into the Title V permit through the administrative amendment process; that the public will not receive another opportunity to provide comments when the requirements are incorporated into the Title V permit; and that EPA review, EPA objection, and petitions to EPA will not be available to the public when requirements from the construction permit are incorporated into the Title V permit.
(2) A copy of the construction permit application is sent to EPA, as provided by 40 CFR § 70.8(a)(1).
(3) A copy of the draft construction permit is sent to any affected State, as provided by 40 C.F.R. § 70.8(b).
(4) A copy of the proposed construction permit is sent to EPA for a 45-day review period as provided by 40 C.F.R.§ 70.8(a) and (c).
(5) The DEQ complies with 40 C.F.R. § 70.8(c) upon the written receipt within the 45-day comment period of any EPA objection to the construction permit. The DEQ shall not issue the permit until EPA's objections are resolved to the satisfaction of EPA.
(6) The DEQ complies with 40 C.F.R. § 70.8(d).
(7) A copy of the final construction permit is sent to EPA as provided by 40 CFR § 70.8(a).
(8) The DEQ shall not issue the proposed construction permit until any affected State and EPA have had an opportunity to review the proposed permit, as provided by these permit conditions.
(9) Any requirements of the construction permit may be reopened for cause after incorporation into the Title V permit by the administrative amendment process, by DEQ as provided in OAC 252:100-8-7.3(a), (b), and (c), and by EPA as provided in 40 C.F.R. § 70.7(f) and (g).

(10) The DEQ shall not issue the administrative permit amendment if performance tests fail to demonstrate that the source is operating in substantial compliance with all permit requirements.

B. To the extent that these conditions are not followed, the Title V permit must go through the Title V review process.

SECTION XXII. CREDIBLE EVIDENCE

For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any provision of the Oklahoma implementation plan, nothing shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

[OAC 252:100-43-6]

Scott A. Thompson
Executive Director

Kevin Stitt
Governor

Valero Refining Company - Oklahoma
Valero Ardmore Refinery
Attn: Mr. Greg Elliott, P.E.
Environmental Manager
One Valero Way
Ardmore, OK 73401

DRAFT

Re: Permit No. **2019-0630-TVR2**
Valero Ardmore Refinery
DEQ Facility ID: 1534
Ardmore, Carter County

Dear Mr. Elliott:

Enclosed is the permit authorizing operation of the referenced facility. Please note that this permit is issued subject to the certain standards and specific conditions that are attached. These conditions must be carefully followed since they define the limits of the permit and will be confirmed by periodic inspections.

Also note that you are required to annually submit an emissions inventory for this facility. An emissions inventory must be completed on approved AQD forms and submitted (hardcopy or electronically) by April 1st of every year. Any questions concerning the form or submittal process should be referred to the Emissions Inventory Staff at 405-702-4100.

If you have any questions, please refer to the permit number above and contact Ryan Buntyn at ryan.buntyn@deq.ok.gov or at (405) 702-4213. Thank you for your cooperation.

Sincerely,

Phillip Fielder, P.E.
Chief Engineer
AIR QUALITY DIVISION

Enclosures

Scott A. Thompson
Executive Director

OKLAHOMA Environmental Quality

Kevin Stitt
Governor

Valero Refining Company - Oklahoma
Valero Ardmore Refinery
Attn: Mr. Greg Elliott, P.E.
Environmental Manager
One Valero Way
Ardmore, OK 73401

Re: Permit No. **2019-0630-TVR2**
Valero Ardmore Refinery
DEQ Facility ID: 1534
Ardmore, Carter County

Dear Mr. Elliott:

Air Quality has completed initial review of the permit application for the referenced facility and completed a draft permit for public review. This application has been determined to be a Tier II application. In accordance with 27A O.S. 2-14-302 and OAC 252:4-7-13(c) the enclosed draft permit is ready for public review. The requirements for public review of the draft permit include the following steps, which **you** must accomplish:

1. Publish at least one legal notice (one day) in at least one newspaper of general circulation within the county where the facility is located (Instructions enclosed);
2. Submit sample notice and provide date of publication to **AQD 5 days prior to notice publishing**;
3. Provide for public review, for a period of 30 days following the date of the newspaper announcement, a copy of the application and draft permit at a convenient location (preferentially at a public location) within the county of the facility;
4. Send AQD a signed affidavit of publication for the notice(s) from Item #1 above within 20 days of publication of the draft permit. Any additional comments or requested changes you have for the draft permit or the application should be submitted within 30 days of publication.

The permit review time is hereby tolled pending the receipt of the affidavit of publication. Please submit the requested information as soon as possible. You should be aware that failure to submit an adequate response within 180 days may result in the withdrawal of your application and forfeiture of your application fees.

If you have any questions, please refer to the permit number above and contact Ryan Buntyn at ryan.buntyn@deq.ok.gov or at (405) 702-4213. Thank you for your cooperation.

Sincerely,

Phillip Fielder

Phillip Fielder, P.E.
Chief Engineer
AIR QUALITY DIVISION

Enclosures

NOTICE OF DRAFT PERMIT
TIER II or TIER III AIR QUALITY PERMIT APPLICATION

APPLICANT RESPONSIBILITIES

Permit applicants are required to give public notice that a Tier II or Tier III draft permit has been prepared by DEQ. The notice must be published in one newspaper local to the site or facility. Note that if either the applicant or the public requests a public meeting, this must be arranged by the DEQ.

1. Complete the public notice using the samples provided by AQD below. Please use the version applicable to the requested permit action;
   Version 1 – Traditional NSR process for a construction permit
   Version 2 – Enhanced NSR process for a construction permit
   Version 3 – initial Title V (Part 70 Source) operating permit, Title V operating permit renewal, Significant Modification to a Title V operating permit, and any Title V operating permit modification incorporating a construction permit that followed Traditional NSR process
2. Determine appropriate newspaper local to facility for publishing;
3. Submit sample notice and provide date of publication to AQD 5 days prior to notice publishing;
4. Upon publication, a signed affidavit of publication must be obtained from the newspaper and sent to AQD.

REQUIRED CONTENT (27A O.S. § 2-14-302 and OAC 252:4-7-13(c))

1. A statement that a Tier II or Tier III draft permit has been prepared by DEQ;
2. Name and address of the applicant;
3. Name, address, driving directions, legal description and county of the site or facility;
4. The type of permit or permit action being sought;
5. A description of activities to be regulated, including an estimate of emissions from the facility;
6. Location(s) where the application and draft permit may be reviewed (a location in the county where the site/facility is located must be included);
7. Name, address, and telephone number of the applicant and DEQ contacts;
8. Any additional information required by DEQ rules or deemed relevant by applicant;
9. A 30-day opportunity to request a formal public meeting on the draft permit.

SAMPLE NOTICE *(Italicized print is to be filled in by the applicant.)***:**

DEQ NOTICE OF TIER *…II or III…* **DRAFT PERMIT**

A Tier *…II or III…* **application for an air quality** *…type of permit or permit action being sought (e.g., significant modification to a Title V permit or Title V/Title V renewal permit)…* **has been filed with the Oklahoma Department of Environmental Quality (DEQ) by applicant,** *…name and address.*

The applicant requests approval to *…brief description of purpose of application…* **at the** *…site/facility name … …***[proposed to be] located at** *…physical address (if any), driving directions, and legal description including county…..*

In response to the application, DEQ has prepared a draft operating permit [modification] (Permit Number: *…xxxx-xxxx-x…***), which may be reviewed at** *…locations (one must be in the county where the site/facility is located)…* **or at the Air Quality Division's main office (see address below). The draft permit is also available for review under Permits for Public Review on the DEQ Web Page: http://www.deq.ok.gov/**

This draft permit would authorize the facility to emit the following regulated pollutants: *(list each pollutant and amounts in tons per year (TPY))* [For facility modifications only, either add**: , which represents** (*identify the emissions change involved in the modification)*, or add: **. The modification will not result in a change in emissions**]

The public comment period ends 30 days after the date of publication of this notice. Any person may submit written comments concerning the draft permit to the Air Quality Division contact listed below or as directed through the corresponding online notice. [Modifications only, add: **Only those issues relevant to the proposed modification(s) are open for comment.**] **A public meeting on the draft permit [modification] may also be requested in writing at the same address. Note that all public meetings are to be arranged and conducted by DEQ staff.**

In addition to the public comment opportunity offered under this notice, this draft permit is subject to U.S. Environmental Protection Agency (EPA) review, EPA objection, and petition to EPA, as provided by 40 CFR § 70.8.

If the Administrator (EPA) does not object to the proposed permit, the public has 60 days following the Administrator's 45-day review period to petition the Administrator to make such an objection as provided in 40 CFR 70.8(d) and in OAC 252:100-8-8(j).

Information on all permit actions including draft permits, proposed permits, final issued permits and applicable review timelines are available in the Air Quality section of the DEQ Web page:
http://www.deq.ok.gov/.

For additional information, contact *…names, addresses and telephone numbers of contact persons for the applicant,* **or contact DEQ at: Chief Engineer, Air Quality Division, 707 N. Robinson, Suite 4100, P.O. Box 1677, Oklahoma City, OK, 73101-1677. Phone No. (405) 702-4100.**

Texas Commission on Environmental Quality
Operating Permits Division (MC 163)
P.O. Box 13087
Austin, TX 78711-3087

Subject: Permit No. **2019-0630-TVR2**
Valero Ardmore Refinery
DEQ Facility ID: 1534
Ardmore, Carter County

Dear Sir / Madam:

The owner/operator of the above-referenced facility has applied for renewal of the Title V operating permit. The Air Quality Division has completed the initial review of the application and prepared a draft permit for public review. Since this facility is within 50 miles of the Oklahoma - Texas border, a copy of the proposed permit will be provided to you upon request. Information on all permit actions and a copy of this draft permit are available for review by the public in the Air Quality Section of DEQ Web Page: *https://deq.ok.gov*.

Thank you for your cooperation. If you have any questions, please refer to the permit number above and contact me or the permit writer at (405) 702-4100.

Sincerely,

Phillip Fielder

Phillip Fielder, P.E.
Permits and Engineering Group Manager
AIR QUALITY DIVISION

Scott A. Thompson
Executive Director

OKLAHOMA Environmental Quality

Kevin Stitt
Governor

Date: April 18, 2022

Chickasaw Nation
Attn: Bill Anoatubby, Governor
P.O. Box 1548,
Ada, OK 74821

Re: Permit Application No. **2019-0630-TVR2**
Valero Refining Company – Oklahoma
Valero Ardmore Refinery (DEQ Facility ID: 1534)
Carter County
Date Received: May 21, 2019

Dear Mr. Anoatubby:

The Oklahoma Department of Environmental Quality (ODEQ), Air Quality Division (AQD), has received the Tier II application referenced above. A Tier II application requires the facility provide a 30-day public comment period on the draft Tier II permit. The process requires the facility to notify the public by newspaper notice in a newspaper in the county of the proposed project. Since the proposed project falls within your Tribal jurisdiction, AQD is providing this direct notice. This letter notification is in addition to the newspaper notice.

Copies of draft permits and comment opportunities are also provided to the public on the ODEQ website at the following location:

https://www.deq.ok.gov/air-quality-division/air-permits/public-participation-issued-permits/

If you prefer a copy of the draft and/or proposed permit, or direct notification by letter for any remaining public comment opportunities, if applicable, on the referenced permit action, please notify me by e-mail at phillip.fielder@deq.ok.gov, or by letter at:

Department of Environmental Quality, Air Quality Division
Attn: Phillip Fielder, Chief Engineer
707 N Robinson
Oklahoma City, OK, 73102

Thank you for your cooperation. If you have any questions, I can also be contacted at (405) 702-4185.

Sincerely,

Phillip Fielder

Phillip Fielder, P.E.
Chief Engineer
AIR QUALITY DIVISION

DRAFT

PART 70 PERMIT

AIR QUALITY DIVISION
STATE OF OKLAHOMA
DEPARTMENT OF ENVIRONMENTAL QUALITY
707 NORTH ROBINSON, SUITE 4100
P.O. BOX 1677
OKLAHOMA CITY, OKLAHOMA 73101-1677

Permit No. 2019-0630-TVR2

Valero Energy Company - Oklahoma,

having complied with the requirements of the law, is hereby granted permission to operate the Valero Ardmore Refinery, located in Sections 16, 17, 20, & 21, T4N, R2E, in Carter County, Oklahoma, in accordance with this permit, subject to Standard Conditions dated July 21, 2016, and the Specific Conditions, both attached.

This permit shall expire five years from the date of issuance, except as authorized under Section VIII of the Standard Conditions.

______________________________ _________________________

Division Director **Date**